

BEFORE THE  
CALIFORNIA ENERGY COMMISSION

In the matter of, )  
 )  
IEPR Lead Commissioner Workshop ) Docket No. 12-IEP-1D  
\_\_\_\_\_ )

Combined Heat and Power to Support  
California's AB 32 Climate Change Scoping Plan

CALIFORNIA ENERGY COMMISSION  
HEARING ROOM A  
1516 NINTH STREET  
SACRAMENTO, CALIFORNIA

THURSDAY, FEBRUARY 16, 2012  
9:00 A.M.

Reported by:  
Kent Odell

## COMMISSIONERS:

Robert Weisenmiller, Chair  
 Carla Peterman, IEPR Lead Commissioner (Absent)

## STAFF:

Suzanne Korosec, IEPR Lead  
 Bryan Neff  
 David Vidaver  
 Rinaldo Aldas, PIER  
 Jim Bartridge

Also Present: (\* Via WebEx)

Cliff Rechtschaffen, California Office of the Governor  
 Sam Ruark, Sonoma County  
 John Hake, EBMUD Energy  
 Bill Martini, Tecogen  
 Joe Allen, Solar Turbines  
 Ken Darrow, ICF International  
 Barbara Barkovich, California Large Energy Consumers Assn.  
 Tom Silva, representing Chevron  
 Tom Casten, ACORE Board member, Recycled Energy Development  
 \*John Ballam, Massachusetts Department of Energy Resources  
 Keith Davidson, DE Solutions  
 Brandon Blizman, Makel Engineering, Inc.  
 Jennifer Kalafut, California Public Utilities Commission  
 Michael Alcantar, Cogeneration Association of California  
 Ray Williams, Pacific Gas & Electric  
 Gerome Torribio, Southern California Edison  
 George Simons, Itron  
 Dave Barker, San Diego Gas & Electric  
 Ray Pingle, Sierra Club  
 Andy Schwartz, California Public Utilities Commission  
 Justin Kubbasek  
 Tim Tutt, SMUD  
 Evelyn Kahl  
 Dennis Peters, CAISO  
 Andy Brown, Ellison, Schneider & Harris  
 Brian Biering, Ellison, Schneider & Harris  
 Beth Vaughan, California Cogeneration Council  
 Greg Wolf, NextEra Energy  
 \*David Erickson

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1 P R O C E E D I N G S

2 FEBRUARY 16, 2012 9:00 A.M.

3 MS. KOROSSEC: All right, good morning everyone.

4 I'm Suzanne Korosec. I manage the Energy Commission's  
5 Integrated Energy Policy Report Unit, and welcome to  
6 today's workshop on the Combined Heat and Power in  
7 California.

8 A couple of housekeeping items before we get  
9 started. Restrooms are in the atrium out the double doors  
10 and to your left. We have a snack room at the top of the  
11 stairs in the atrium on the second floor under the white  
12 awning. And if there is an emergency and we need to  
13 evacuate the building, please follow the staff out the  
14 door to the park that is kitty corner to the building.

15 Today's workshop is being broadcast through our  
16 WebEx Conferencing System and parties do need to be aware  
17 that you're being recorded. We'll make an audio recording  
18 available on our website a couple of days after the  
19 workshop, and then we'll provide a written transcript in  
20 about two weeks.

21 We do have a full agenda today and Brian will go  
22 over that in a moment, but I do want to mention that there  
23 is a general public comment period at the very end of  
24 today's workshop, and during that period we'll take  
25 comments first from those of you here in the room, and

1 then from those participating via WebEx. When you're  
2 making comments or when you're asking questions during the  
3 day, please come up to one of the microphones so that we  
4 can make sure we capture your comments in the transcript,  
5 and so that the WebEx folks can hear you. And it's also  
6 helpful if you can give our transcriber your business  
7 cards so we make sure that your name and affiliation are  
8 spelled correctly in the transcript.

9           For WebEx participants, you can use either the  
10 chat or raised hand functions to let our WebEx Coordinator  
11 know that you'd like to make a comment, and we'll either  
12 relay your question or we'll open your line at the  
13 appropriate time.

14           We're also accepting written comments on today's  
15 topics until close of business March 9th, and the Notice  
16 for today's workshop, which is available on the table in  
17 the foyer and also on our website, describes the process  
18 for submitting comments to the IEPR Docket.

19           As I said, we do have a full agenda, I won't take  
20 up much more of your time, but I do want to provide just  
21 some brief context for how today's workshop fits in within  
22 the Integrate Energy Policy Report Proceeding. The Energy  
23 Commission prepares an IEPR every two years with  
24 assessments of energy supply, demand, price, transmission,  
25 distribution, and market trends that are then used to

1 develop recommendations to the Governor for California's  
2 Energy policies.

3           The 2011 IEPR was approved by the Commission last  
4 week and one of the areas identified as needing further  
5 analysis in both the 2012 IEPR Update and the 2013 IEPR is  
6 the important contribution of CHP to California's Clean  
7 Energy Goals, as well as Governor Brown's Clean Energy  
8 Jobs Plan goal of adding 6,500 megawatts of new CHP by  
9 2020.

10           The 2011 IEPR emphasized the need for the Energy  
11 Commission to update past assessments of CHP potential and  
12 to develop forecasting methods and scenarios that more  
13 accurately account for the potential contribution of CHP  
14 to California's energy mix. The discussions and feedback  
15 from today's workshop will feed into that, efforts to  
16 better reflect CHP goals in our electricity and natural  
17 gas demand forecast, and will also influence our analysis  
18 of electricity infrastructure that is needed to satisfy  
19 future demand, maintain reliability, and achieve our clean  
20 energy goals.

21           So with that, I'll turn it over to the dais for  
22 opening remarks.

23           CHAIRMAN WEISENMILLER: Thank you, Suzanne. First  
24 I would note that Commissioner Peterman is sick this  
25 morning, so Jim Bartridge will be sitting in for her.



1 Certainly, this is a workshop she's been looking forward  
2 to, so we both regret she's not here today, but I am sure  
3 Jim will sort of fill her in and will probably have a few  
4 words in a second.

5 As Suzanne said, last year's focus was really on  
6 renewable DG and this year was turning attention more to  
7 CHP, or Cogeneration, or recycled power. And I think  
8 everyone knows that energy efficiency is really at the top  
9 of the loading order in California, and oftentimes we  
10 think of energy efficiency in the sense of buildings and  
11 appliances, making those more efficient. But certainly,  
12 cogeneration has always been a key way to basically have a  
13 much more efficient industrial system. And when I first  
14 came to the Energy Commission in '77-'82, I was  
15 responsible for the getting the State's programs in  
16 Cogeneration set up. And I remember at that time, at  
17 least once a month the then Chairman of the Energy  
18 Commission, Richard Mullen, would call me in and say he  
19 had gotten a call from the Governor wanting to know what  
20 have we done on cogen, why wasn't there any action or  
21 progress there. And every month, I continued to scramble  
22 and I guess, as we're now --

23 MR. RECHTSCHAFFEN: [Phone ringing] He's calling  
24 right now.

25 CHAIRMAN WEISENMILLER: Probably is -- so this

1 remains -- this was and certainly remains a very high  
2 priority for the Governor. I think Cliff's presence here  
3 sort of symbolizes that, and certainly a very high  
4 priority for me.

5 I think in that time we made a lot of progress and  
6 I want to really tip my hat in part to the leadership,  
7 then, of not just the Governor, but certainly Commissioner  
8 Detrich at the PUC was really a leader there, Commissioner  
9 Reed here, Suzanne Reed was a leader, and Mary Nichols of  
10 the ARB was very much a leader in that area. And  
11 certainly one of the other inspirations certainly in OII  
12 26 for those of you who weren't there, certainly, there is  
13 a great book by David Roe, Dynamos and Virgins, that went  
14 through that series. But the Environmental Defense Fund  
15 particularly was very instrumental in the State's  
16 cogeneration push; Tom Graff certainly took a very  
17 visionary role on that.

18 And certainly we got things moving, and one of the  
19 ways we did that, again at that point, as sometimes now we  
20 have the utilities policy and cogen, is just to say no,  
21 and that's not acceptable. And certainly, we're looking  
22 for creativity to try to move forward. At that point,  
23 obviously, one of the ways the PUC got the utilities'  
24 attention was PG&E was fined for inadequate progress on  
25 cogen. And I think, again, that's a symbol of that, the

1 State takes these goals very seriously. So with that, do  
2 you have any words?

3 MR. RECHTSCHAFFEN: Thanks very much, Chair  
4 Weisenmiller. As Bob said, this is a priority for the  
5 Governor. He has said, "By installing equipment to  
6 produce electricity from heat now wasted, industries can  
7 reduce overall fuel use and drastically decrease energy  
8 costs." Now, he said that in 1981 and it wasn't called  
9 Combined Heat and Power then, it was Cogeneration, and  
10 Chair Weisenmiller had a lot fewer gray hairs, but he was  
11 instrumental in setting the policy then. And Governor  
12 Brown has been a leader in developing this technology  
13 since his first Administration.

14 We made a lot of progress back in the 1980's and  
15 1990's. We have 8,500 megawatts here, we'll talk a lot  
16 about that. We are second to Texas and Governor Brown  
17 doesn't like being second to Texas in anything, let alone  
18 in the clean energy field. I don't know if we can catch  
19 Texas given all of their oil and gas operations, and we're  
20 probably half of where they are. But we've done a lot  
21 less since the '80s and '90s, and we need to do more. We  
22 need to do more for lots of reasons, as Bob mentioned. We  
23 need to do more to reach our efficiency goals, we need to  
24 do more to reach our greenhouse gas goals, this is a major  
25 part of the AB 32 Scoping Plan, and we need to do more to

1 help us meet load in constrained areas, and to save money,  
2 to save energy costs in an era of rising costs. The  
3 Governor is firmly committed to doing this, he doesn't  
4 call us once a week about this, but he may once we start  
5 getting going, he has a clean energy plan that he outlined  
6 in the campaign to call for 6,500 megawatts of new  
7 generation by 2030, and he's firmly committed to putting  
8 us on a path to get there, and this is the start of a  
9 process that the Administration is going to be focused on  
10 to figure out the best strategies that we all collectively  
11 can work on to get there, not just the Energy Commission,  
12 but the Public Utilities Commission, the ISO, the Air  
13 Board, and other agencies.

14 We've made some landmark progress recently with  
15 the QF Settlement, with the implementation of the feed in  
16 tariff for small operations, but there are lots of  
17 regulatory challenges that remain, market challenges and  
18 others. I look forward to the rest of today's workshop to  
19 hear about not just the potential or the challenges, but  
20 strategies that people can suggest for moving forward and  
21 achieving these important goals. Thanks very much.

22 MR. BARTRIDGE: Good morning. I will just say  
23 Commissioner Peterman sends her regards today and  
24 apologizes that she couldn't be with us. She sees cogen  
25 as an important part of meeting the State's energy Policy

1 goals and looks forward to further understanding the  
2 technical and market potential of new cogen, as well as  
3 what we can do to remove market barriers to new CHP.

4 MR. NEFF: Wonderful. I'm Bryan Neff. I work in  
5 the Electricity Analysis Office, and first I'd like to  
6 thank everybody for coming today. It's an important day  
7 and hope to get a lot out of it.

8 So everybody and many of us show up every day  
9 working towards California's goals and, just as the  
10 Commissioners have talked about, they're very lofty and we  
11 hope to get there. And part of what we're doing to try  
12 and get there is, today, to build the public record that  
13 will be used in the 2012 Integrated Energy Policy Report  
14 and the other documents that the Energy Commission  
15 creates, and will focus on what it's going to take and  
16 what are the implications of reaching those goals.

17 So today we're going to be starting with the ICF  
18 Report and its state of the possible future development of  
19 CHP and existing State policies, the prospective  
20 development that will occur from that, and then provide a  
21 technical analysis based on a pricing model, and gives the  
22 context for existing and potential CHP State Policies. It  
23 provides megawatt forecasts that can be used as  
24 guideposts, providing context with which to evaluate  
25 potential policy actions.

1           Following that is a small CHP Market Panel, it's  
2   made up of Project Managers and CHP Manufacturers. The  
3   Project Managers will be presenting on their experiences  
4   with specific projects they have worked on or are  
5   currently working on, presenting the difficulties they  
6   encountered, but did not stop them, but may have stopped  
7   many others. We also hear from Technology Manufacturers  
8   who have developed and manufactured their technology in  
9   California, yet have been less successful in selling it  
10  here.

11           Later, we will hear about Industrial CHP issues.  
12  Although these projects usually fall in the size range of  
13  the small CHP market, their experiences spread over the  
14  entire industry and effect policies that have widespread  
15  impact.

16           In the afternoon, we'll be hearing some innovative  
17  ideas for CHP Financing, some of the novel ways that make  
18  CHP projects viable based on its operating  
19  characteristics, as well as about the approach in another  
20  state, what Massachusetts has done to level the playing  
21  field for the various technologies that provide energy  
22  efficiency and greenhouse gas savings.

23           After that, we're going to focus on Research and  
24  Development that has always played a role in helping the  
25  state meet its goals, and for CHP it's no different. We

1 will hear from the Commission's PIER Program about the  
2 current work that's being done to meet some of these  
3 existing barriers and overcome some regulatory hurdles.

4 And finally, we'll shift our attention to the  
5 impact CHP development will have on infrastructure  
6 planning. The three investor-owned utilities play a major  
7 role in development and we also hear from them, as well as  
8 from the CPUC and developers who also sit at the table.

9 We have a busy day, so in getting started, I'm  
10 going to now introduce Ken Darrow, who is a Senior  
11 Technical Specialist at ICF. He is responsible for  
12 economic, market, and strategic analyses for energy  
13 technologies and markets. Mr. Darrow has over 30 years of  
14 experience evaluating energy technologies and markets,  
15 conducting regulatory analysis, and managing international  
16 technology transfer and market transformation. He has  
17 contributed to numerous Distributed Generation studies,  
18 technology specific assessment of advanced distributed  
19 generation technologies, and their application, and  
20 application focus studies such as the assessment of CHP  
21 market opportunities, including the 2005 California Market  
22 Assessment Report and the 2009 California CHP Market  
23 Assessment Report Update.

24 MR. DARROW: Thank you, Bryan. Good morning,  
25 Commissioners and good morning to all of you. As Bryan

1 mentioned, I'm going to talk about the work that we just  
2 completed on a revised Combined Heat and Power Market  
3 Assessment. Another member of our team is here today,  
4 Eric Wong, has been active for a long time in the  
5 California CHP business, and he led the policy analysis,  
6 and if he could just wave in the back if anyone has any  
7 policy specific questions, or if I fall down and need to  
8 be bailed out, he's here to take over.

9           So I have a lot of material, some of it is fairly  
10 dry and boring, but I want to try to go through it  
11 intelligibly, yet fairly quickly. So the first part of  
12 the discussion is on the Market Characterization that we  
13 did looking at the policies that effect CHP, identifying  
14 and categorizing and quantifying existing CHP, determining  
15 what business facilities in California have the potential  
16 to add new CHP, and evaluating the electric and gas prices  
17 today and in the future, and looking at the CHP technology  
18 cost and performance. And all of those assumptions go  
19 into the basic economic equation for whether CHP gets  
20 adopted or not.

21           And then the second half, I'm going to talk  
22 specifically about how we treated some of the policy  
23 assumptions in our scenario analysis, and then present the  
24 results of three cases that we ran, a base case, a medium,  
25 and a high case, and look at the greenhouse gas emissions



1 implications, and then provide some conclusions from the  
2 work.

3 I've been asked to maybe open up a couple of times  
4 for questions, so I think after we complete the Market  
5 Characterization, if there are any questions, of course, I  
6 welcome the Commissioners to interrupt me at any time with  
7 questions. So let's just move forward, then.

8 The first topic we're looking at is the Policy  
9 Landscape. I talk about all of these policies later in  
10 specifics as to how they're modeled, so rather than go  
11 through all the detail that is on the slide, I'll just  
12 mention that we looked at, in terms of the QF Settlement  
13 Agreement and the AB 1613 Export Feed In Tariff for CHP  
14 systems less than 20 megawatts, the expanded Self  
15 Generation Incentive Program, and the Renewable Portfolio  
16 Standard, which doesn't directly affect CHP, but affects  
17 it indirectly, and cap-and-trade, which is the same thing,  
18 there's an indirect effect on CHP from cap-and-trade. And  
19 then, also, the issues of the Distribution System  
20 Interconnection Settlement Agreement.

21 Certainly, for the first five of these on the  
22 list, they're all explicitly modeled in the work that we  
23 did and I'll explain that as we move on.

24 The first area of analysis on Existing CHP shows  
25 the ICF keeps what is called the ICF CHP Installation

1 Database nationally of U.S., and in California we estimate  
2 that there's 1,200 CHP sites producing 8,518 MW of power.  
3 One of our functions on this project was to reconcile some  
4 differences in our database with numbers that the Energy  
5 Commission has and that the CPUC had, and we were given  
6 access to some of the confidential data sources, and went  
7 through and verified and compared, and while there are  
8 still differences in coverage and definition on certain  
9 sites, and inclusion of sites, we feel that we have a good  
10 number for moving forward. The details of the  
11 reconciliation will be in the report when it's released.

12 Just focusing on the pie chart here of the CHP  
13 that's here, about half of it is in the industrial sector,  
14 and about a third is in enhanced oil recovery, the red pie  
15 slice. And then about less than a quarter, the remaining,  
16 is in mostly commercial which includes institutional and  
17 government, and a small amount in other.

18 I don't show a split in size, but I was asked to  
19 talk about it, so the breakdown by size, actually 85  
20 percent of this total capacity is in 112 sites that are  
21 larger than 20 MW, and a lot of the sites are  
22 significantly larger than 20 MW. So nine percent of the  
23 sites produce 85 percent of the capacity. And the small  
24 market which is indicated in the bullets there, of 1,282  
25 MW at 1,090 sites. So 91 percent of the sites produce 15

1 percent of the -- or account for 15 percent of the  
2 capacity.

3           And while it is true that Texas leads the country  
4 in total existing CHP capacity, very very little of that  
5 capacity in Texas is in what you would call distributed  
6 generation. And I think California leads the nation, by  
7 far, in terms of the development of the distribution  
8 generation side of the CHP market.

9           The next thing I wanted to look at on existing CHP  
10 is the distribution by utility. Over half of the existing  
11 capacity is in PG&E territory. PG&E is blessed with a lot  
12 of applications that are very CHP favorable. I don't know  
13 if they feel it's a blessing all the time, but they have  
14 two-thirds of the enhanced oil recovery capacity in their  
15 territory and, by far, they have five times the food  
16 processing facilities that are in the southern part of the  
17 state.

18           They also have most of the paper mills and they're  
19 roughly equal in refining capacity between north and  
20 south, but they also lead in CHP and education facilities  
21 and, in the very last super large CHP plant that was built  
22 in 2001 is in their territory, attached to a steel mill.  
23 So they have specific markets and environment unique to  
24 the northern part of the state that reflect their  
25 dominance in this number.

1           So moving on from the existing CHP, I want to  
2 briefly describe how we calculate the future technical  
3 potential. We evaluate markets that have a good electric  
4 load factor and thermal loads that could technically  
5 support a CHP system with a high load factor and high  
6 thermal utilization. And those types of industries are  
7 the large process industries, many of which already have  
8 CHP, the enhanced oil recovery market, large and medium  
9 commercial and institutional establishments, education,  
10 health care, hotels. And the report will have a complete  
11 list of the sectors that we analyzed. We also  
12 specifically look at markets where we're using a portion  
13 of the thermal energy to replace electric air-  
14 conditioning, markets like office buildings and retail and  
15 expanding the potential market for CHP that way.

16           So based on all those applications, we identify  
17 the active sites in the state using the Dunn & Bradstreet  
18 database; there is not energy information in that  
19 database, but based on other work that we've done that  
20 relate energy use to business activity, we estimate  
21 electric and thermal loads for each application in each  
22 site. And that results in the total technical potential,  
23 and from that we subtract the existing CHP to get the  
24 remaining potential that can compete for new market share.

25           So there's a lot more to it than that and those

1 details will be in the report.

2           The summary of the CHP technical potential is  
3 shown on this slide by size. These five sizes across the  
4 top of the table reflect the five size bins that we  
5 analyze in the model, and there's a total of close to 16  
6 gigawatts of remaining technical potential and about a  
7 third of that is in export potential, and two-thirds of  
8 that is for electricity that would be used by the facility  
9 itself, onsite.

10           There are some other things I want to point out on  
11 this slide, is that if you look again at these big market  
12 systems, and there really are essentially two CHP markets  
13 in California, for large systems and for distributed  
14 systems, and if you look at the over 20 MW size, 80  
15 percent of that market potential is in the export market.  
16 So export is a much more important driver for large  
17 systems than it is for small systems. And if you look at  
18 the export potential for the smaller systems, it adds up  
19 to about 1,236 MW. That's the potential that we see that  
20 is eligible under AB 1613.

21           One thing I want to point out before leaving this  
22 slide is we've used the term "Existing CHP" in the  
23 previous slide, and now we're saying "Existing  
24 Facilities." We're talking about businesses that are  
25 existing, not that they have CHP already, so, really, that

1 has caused confusion in the past. So these are capacity  
2 where CHP could be added.

3 Then, another part of the competition for CHP is  
4 the price comparison between electricity and gas, and we  
5 analyzed electricity prices in terms of where they are now  
6 and we did that using the existing tariffs and prices for  
7 both electric and gas. And for the price movement over  
8 time, over the next 20 years, we have a 20-year time  
9 horizon, we pin that to the EIA 2011 Annual Energy Outlook  
10 Reference Case and the specific measure that we used there  
11 was the wellhead gas price. And the wellhead gas price  
12 determines the commodity cost of gas that goes into the  
13 gas prices, and we also estimated its impact on  
14 calculating a combined cycle power cost and used that  
15 escalation over time to reflect the escalation of  
16 generation cost for the utilities. There are a lot of  
17 details in all the tariffs and cookbook calculations and  
18 things, and so it's kind of difficult to work through all  
19 that, but that's the general idea of what we did.

20 The next slide compares the wellhead price  
21 forecast that we used this time vs. what was used in 2009.  
22 The red line is the 2011 Reference Case and that reflects  
23 about a 1.8 percent per year real growth in gas prices,  
24 whereas in 2009, and that was the 2009 EIA Stimulus Case,  
25 and that had a 3.4 percent increase in prices, so nearly

1 twice as much. So while gas prices now are much lower and  
2 that would seem to be a very positive factor, I will talk  
3 later about the impact of cap and trade, but right now  
4 while I'm on this slide, I'll just say that, by 2030 in  
5 our analysis, we're adding about \$2.65 to the cost of gas  
6 as a result of the GHG Allowance Cost. And that  
7 essentially would bring that red line all the way up to  
8 the line above it. So the growth rate with cap and trade  
9 for gas prices, effective gas prices, has now gone from  
10 1.8 percent back up to over 3 percent. So it's a very  
11 significant impact on the economics, which I'll talk more  
12 about later.

13           The Intrastate Gas Transportation Cost, I don't  
14 want to talk too much about it other than that CHP is  
15 eligible for a specific transportation rate which is quite  
16 a bit lower than the standard rate that a boiler customer  
17 would have, and so the effective costs are reduced. And  
18 the costs are also reduced because a CHP customer would be  
19 consuming a lot more gas than just existing boiler load,  
20 so there's a double decrease effect, one is a shift in the  
21 right category, and the other is the increase in volume.  
22 And it acts to augment the savings from the avoided boiler  
23 fuels.

24           On to the electric prices. We looked at the rates  
25 in the five size bins that were in that technical

1 potential chart. This is showing the 50 to 500 KW which  
2 is the smallest CHP size category we looked at. We  
3 analyzed the retail rates and calculated an average high  
4 load factor cost, low load factor cost, and an avoided  
5 air-conditioning cost for use in our analysis. And as you  
6 can see, the lower the load factor you go, the higher the  
7 impact or the effect of demand charges and other rates  
8 that raise the average cost much higher.

9           The next slide is for the largest category, 20 MW.  
10 I'm not going to say anything about that. All of the  
11 pricing information should be in the report when it is  
12 released. But what I was showing before was the average  
13 retail rate. The CHP customer or the generator isn't  
14 going to be able to save this entire rate, and so we  
15 calculate what we're calling an Average Avoidable Rate.  
16 When you operate a CHP system, there are certain  
17 unavoidable costs that exist. You can't avoid your  
18 customer charges. If you have forced outages, you'll  
19 trigger demand charges for the entire month, and so if the  
20 system goes offline in a forced outage two or three times  
21 a year, each time you'll have demand charges. And what's  
22 becoming larger over time are the non-bypassable charges  
23 for CHP, and those include the public purpose program  
24 charge, the DWR bond charge, and the nuclear  
25 decommissioning. The most important one is the public



1 purpose charge and that's well over a penny now, it's  
2 approaching 1.5 cents in some customer categories. And  
3 the DWR bond charge is about a half cent. So it's a  
4 significant part of the non-bypassable charges. And then  
5 there are the standby reservation charges -- and this last  
6 bullet here, I want to correct, it's 10 to 30 percent of  
7 the retail costs are unavoidable and up to three cents per  
8 KW hour. So if you're making note, that number has been  
9 changed. So the difference between the blue line, which  
10 is the average retail, and the red line is what a CHP  
11 customer can actually save, and so it's these avoidable  
12 costs that go into the model for the economic calculation.

13           And within the five size categories, we have 12  
14 technologies that were competing within the four  
15 categories of fuel cells, microturbines, reciprocating  
16 engines, and gas turbines. And for each of those  
17 technologies, we've estimated the capital costs, the heat  
18 rate, the thermal energy available, and the operating and  
19 maintenance costs. And what this slide is showing is  
20 average U.S. capital cost. In California, the  
21 construction costs are somewhat higher than the rest of  
22 the country, particularly in the northern part, the Bay  
23 Area. So we increased these U.S. average costs by three  
24 to 10 percent, depending on the location, to reflect the  
25 increased cost. And also, we add emissions after

1 treatment cost because all the reciprocating engines and  
2 the large reciprocating engines and gas turbines are  
3 assumed to have selective catalytic reduction systems.  
4 And in the economic analysis, those capital costs are then  
5 adjusted with any program adjustments like SGIP and tax  
6 credits, the Federal tax credits are included, and any  
7 other State Capital incentives.

8           And it's the combination of the energy prices and  
9 the performance of the CHP system within each of the  
10 market sectors that determines the economic value of CHP,  
11 which in turn determines the market.

12           I don't know if now is a good time to ask if there  
13 are any questions on the basic assumptions on cost and --

14           CHAIRMAN WEISENMILLER: Yeah, I have one question.  
15 One of the legacy systems in California that has been  
16 around in, say, San Francisco, there's a district heating  
17 system, certainly there have been district heating systems  
18 in San Diego and some of the other cities, Sacramento,  
19 actually we have the new central plant for the State  
20 facilities. So in your analysis looking at the potential,  
21 did you consider expanded roles of District heating?

22           MR. DARROW: We really did not. We looked at  
23 systems facility-by-facility, building-by-building,  
24 factory-by-factory. Some district heating systems focus  
25 on steam, they don't have car production, so, no, we

1 didn't specifically look at district heating, although the  
2 facilities that would sign on with the district heating  
3 system are covered and analyzed individually, but the  
4 economics of maybe a larger more efficient system serving  
5 all of them together was not then considered.

6 CHAIRMAN WEISENMILLER: Okay, obviously district  
7 heating has been a key part of CHP in Europe like Denmark;  
8 do you have a sense of what sort of bump up we might get  
9 with that? Or is it just too tough to generalize?

10 MR. DARROW: Well, one thing is that of course you  
11 get an economy of scale if you're talking about a large  
12 scale system in terms of the lower capital cost and  
13 greater efficiency, so the economics, I think, would  
14 improve. But I don't know what extent you would -- I  
15 still think the way the California market is laid out,  
16 there's certainly opportunities for those systems in the  
17 city center and we have the capability, I guess, to  
18 analyze the technical potential by Zip Code and things,  
19 and try to specifically analyze a District heating  
20 opportunity, but to generalize about it from the overall  
21 State data, I don't know. I mean, I certainly think it  
22 would -- if you find a collection of willing customers  
23 with good steam and electric loads, and you could put in a  
24 large air-conditioning, cooling, chilled water system, you  
25 know, steam, then I think you would improve economics, but

1 largely in certain commercial markets which are important,  
2 but they're not the biggest part of the potential, I  
3 think.

4 CHAIRMAN WEISENMILLER: Okay, thanks.

5 MR. DARROW: Well, I think I'll move on, then.  
6 We've actually made it to talking about the cases  
7 themselves, although not quite. This is just repeating  
8 the base case. The base case includes policy assumptions  
9 that are felt that they're in place and underway. Now,  
10 not all the details of all these programs are fully in  
11 place and underway, but they pretty much define the view  
12 of the future if nothing else changes. So that includes  
13 the 33 percent RPS and the cap and trade, and the AB 1613  
14 export, and also maybe a short run avoided cost -- short  
15 run average cost pricing for the large export. And I'll  
16 go over in the next slides how we actually estimated  
17 these. I'll try to speed up a little maybe.

18 So cap and trade is -- the way it affects the  
19 market is, first it was the allowance price, which I've  
20 listed second there, the price assumptions, how much is  
21 the allowance price going to cost you, and then what is  
22 your fossil or carbon exposure. So, in terms of the  
23 quantity assumptions for the utilities, we base their  
24 average GHG emissions on the E3 GHG Calculator that is on  
25 their website and referenced in the CPUC website, it was

1 their scenario 2, and then that gives GHG emissions over  
2 time. The emissions for CHP are based on the net increase  
3 in gas use compared to the avoided boiler fuel and the  
4 added generator fuel. And that's a specific rate of  
5 conversion.

6 And the price assumptions, we made a number of --  
7 we looked at different options and eventually we decided  
8 to use the synapse forecast that has been used in the 2011  
9 Market Price Referent Analysis and it's also been cited in  
10 the long term procurement planning process, and I'll show  
11 what that is on a later slide.

12 Two other things that are important in pricing is  
13 that, while it's not really set, about -- we estimated  
14 that a 90 percent reimbursement of the cost, or 90 percent  
15 of the cost increases for retail electric rates would be  
16 reimbursed, and that there would be no reimbursement for  
17 any effective fuel cost increases for onsite CHP systems.  
18 And it's our understanding of that's how the discussions  
19 are now that the program would work.

20 This is just the Synapse Forecast. We're using  
21 the dark red line, which is the real version of the  
22 nominal price increases are shown in the faint dotted  
23 line. So in 2020, the nominal price is \$46.80 per metric  
24 ton, which translates to \$37.47 in the way we use it in  
25 the model. So those are the price forecasts as we've used

1    them.

2               One of the things that I was asked to do was,  
3    because this is an important and sensitive issue, is to  
4    determine how sensitive our output would be to the GHG  
5    assumptions, and I know I haven't gotten to the outputs  
6    yet, but it was felt that I should talk about this now, so  
7    I -- I'm comparing this to the base case, which I haven't  
8    yet presented, again, I apologize; but in the absence of  
9    the CHP Program as I've defined it, the CHP market  
10   penetration would be 18.8 percent higher, so turning that  
11   around the other way, going from no cap and trade to cap  
12   and trade is a significant reduction in market penetration  
13   for CHP.

14              Now we looked at using the low price track vs. the  
15   high price track and that does -- the low price would  
16   increase penetration compared to the medium price track by  
17   5.8 percent, and the high price would lower it by 3.7, and  
18   then we also looked at taking away the assumption of  
19   electric reimbursement and that would increase market  
20   penetration for CHP by 11 percent because essentially in  
21   that scenario, you've got everybody having their prices  
22   going up.  CHP fuel would go up percentage-wise a little  
23   more than the average electric, but that would be a  
24   difference.  So I think this shows that cap and trade is a  
25   fairly strong inhibitor of market penetration in the case

1 where you have reimbursement of the price impacts on the  
2 electric side, but not on the gas side.

3 So these are basically the average emissions of  
4 utilities and, again, this was taken from E3. They only  
5 went out to 2020, so we extrapolated from 2020 to 2030 and  
6 what we did, there were three utilities that were quite a  
7 bit lower, and we just assumed that they would stay  
8 constant at that very low rate, and that the four  
9 utilities that were higher, they would continue to reduce  
10 their emissions over time at the rate of about one percent  
11 per year. And, again, the gas emissions are based on 117  
12 pounds per million Btu, it's a fairly homogenous fuel and  
13 so it's pretty much a straight calculation.

14 That covers the impact of cap and trade. The  
15 Renewable Portfolio Program is expected to have an impact  
16 on electric rates. We really didn't have a way to know  
17 what that was, so, again, we went to the GHG Calculator,  
18 Scenario 2, the Accelerated Policy Case, included the RPS  
19 and high energy efficiency, and in the results of that,  
20 they said that the average utility rate increase by 2020  
21 was 1.64 cents per kilowatt hour. And so our analysis is  
22 in four time periods in five-year increments, so we  
23 average that out through 2020, and then after 2020 we just  
24 assumed that price increase was constant and would not go  
25 up.

1           We included SGIP with the .50 a watt, or \$500.00 a  
2 kilowatt for non-fuel cell, this is a 50-50 payment with  
3 half up front and half over five years for systems that  
4 meet a minimum 80 percent load factor. We had some  
5 markets that don't meet that load factor and we prorated  
6 the annual benefits for those markets. And in the base  
7 case, we assume the program would end as scheduled in  
8 January of 2016. There is a program reduction of 10  
9 percent per year for fuel cells and five percent for other  
10 technologies. And then the market -- we assumed the  
11 program ended in 2016.

12           Now, export pricing is an important issue and it's  
13 separate from the retail rates. The AB 1613 pricing, I  
14 believe all the IOUs have tariffs and SMUD has a tariff,  
15 and LADWP is developing a tariff. This is an example of a  
16 calculated tariff and it ranges from around 6.1 cents per  
17 kilowatt hour in the first time period to about 7.3 or 7.4  
18 by the end. And these are based on -- oh, and there are  
19 scheduling costs that are included in that chart for  
20 systems over one megawatt. And I feel that the pricing  
21 does reflect long run marginal cost principles for CHP to  
22 meet.

23           So for the large export pricing, a lot of that is  
24 under development and discussion and also pricing is  
25 something that ultimately will probably have to come in



1 the form of bidding process rather than being given a  
2 tariff rate or a price. But for the purposes of the model  
3 analysis for the base case, I calculated the short run  
4 average cost price which is in use now as part of the  
5 settlement agreement in some of those contracts, and it's  
6 fairly low, it doesn't provide full capital recovery. And  
7 for the medium and high cases, I looked at the 2011 Market  
8 Price Referent, which is based on a long run marginal cost  
9 of power to the electric power system.

10 And the MPR prices are about 25 to 35 percent  
11 higher than the SRAC prices. And again, the SRAC we used  
12 in the Base Case and the MPR pricing we used in the higher  
13 cases.

14 I've just got a few more assumptions before I  
15 actually tell you what it all meant in terms of results,  
16 but the medium case, we included the RPS and cap and  
17 trade, the same as the Base Case. The SGIP Program was  
18 assumed to be extended with this phased reduction in  
19 benefits over time until the benefits drop to zero. And  
20 we also redefined the export market with aggressive  
21 pricing, MPR pricing, and also aggressive market response.  
22 We changed the market response rates for paybacks less  
23 than five years to reflect the strong market response.  
24 This was a comment that was made in 2009, that these  
25 facilities, if they receive a strong signal and address

1 issues of risk, they're ready to proceed with projects.  
2 Note that there is material in the back-up, there actually  
3 is no back-up material, I apologize, so I have to ignore  
4 that.

5           Then, the high case, we added a number of  
6 additional policy measures that would stimulate the prices  
7 and that includes the reimbursement for the GHG allowance  
8 component of CHP fuel costs. So, as I said, in the base  
9 case, there was no reimbursement of this added cost, where  
10 there was reimbursement on the electric side, and in the  
11 high case, we are proposing reimbursement. Although, in a  
12 lot of these scenarios, they're not developed detailed  
13 policy guidance on how you achieve it, but we're just  
14 assuming "if you did this, what would happen," not how are  
15 you going to make it happen.

16           And the next thing we looked at was eliminating  
17 the non-bypassable charges and, to a certain extent,  
18 eliminating what I'm calling double demand charges where  
19 the CHP generator has to pay a reservations charge, demand  
20 charge, but then also pay additional demand charges when  
21 the system goes down on top of that. So we went through  
22 the rates and assumed that those three non-bypassable  
23 charges could be avoided.

24           All right, so there are some additional  
25 assumptions that -- we call this High Electric focus

1 electric utility participation, again, I don't have a  
2 specific mechanism for how electric utilities would  
3 participate, but in 2009 when we looked at the large  
4 market, we were assuming that people would be putting in  
5 combined cycle power systems and we were told that the  
6 business facilities, the refineries, chemical plants,  
7 their main focus is on their steam load, they're not  
8 electric focus, maybe simple cycle. So we assume that,  
9 with a different kind of participation and ownership rate  
10 that additional large combined cycle plants could be built  
11 that would meet a higher percentage of electric load for  
12 the same steam load. And so we call that the Electric  
13 Focus Case. We added a 10 percent State Investment Tax  
14 Credit with no size limit and no end date. We looked at  
15 an additional 10 percent reduction in out year, CHP  
16 capital cost to reflect a more active market, more  
17 competitive market, more competitive pricing, and removal  
18 of a lot of costs that occur in early entry market. And  
19 then more of a modeling change to reflect perception of  
20 risk, as we made the market more CHP friendly, we started  
21 dialing down some of these risk filters, percentages, so  
22 we allowed more participation in the market, and mean  
23 increase went up a percent -- I'll show that a little bit  
24 more. The last thing we added was a \$50.00 a kilowatt T&D  
25 capacity deferral payment for CHP less than 20 MW to

1 reflect grid support at the distribution level.

2           So this is just the table that shows percentages  
3 for each of the cases in the size bins, and those are  
4 percentages that reflect maximum market participation. So  
5 in each of these sizes, we held back some of the technical  
6 potential as a reflection of perceived risk, lack of  
7 space, lack of financing, not interested, but as you make  
8 the market better and better, we assumed that the  
9 participation rates would go up. And while this is a  
10 judgmental input factor, it is something that we tried to  
11 keep in line proportionately with the increases in market  
12 penetration without it.

13           So finally, we have some results. I apologize  
14 for leading up to this in such a long fashion, but.... If  
15 there are any questions now, or should I just jump right  
16 to the --

17           CHAIRMAN WEISENMILLER: Well, we are running  
18 behind, so let's jump on.

19           MR. DARROW: All right. So we ran the three  
20 cases, the blue is the Base Case, the red is the Medium  
21 Case, and the green -- and ranging from the Base Case, 20-  
22 year market penetration of just under 2,000 MW to the High  
23 Case of 6,100 MW. I'm just going to show another split of  
24 the three curves by the onsite market in the light blue,  
25 the export market in the maroon, and then the beige color

1 is the avoided air-conditioned. So in the Base Case  
2 Market, 80 percent of the total market penetration is in  
3 the onsite market; only 11 percent is in export, and the  
4 reason for that is that the SRAC pricing doesn't provide  
5 much of any stimulus for new large CHP export projects.  
6 The AB 1613 tariffs, while higher than the SRAC price, are  
7 sometimes difficult for smaller systems to compete with  
8 because the avoided price is based on a large combined  
9 cycle system.

10           So anyway, in the Base Case, there's very little  
11 export penetration, it's mostly onsite. And in all of the  
12 sectors, the avoided air-conditioning is a fairly constant  
13 10-11 percent of the total onsite penetration. In the  
14 Medium Case Market, the onsite penetration increased by  
15 267 MW, that was entirely due to the one onsite measure  
16 that was added, which was extending the SGIP Program,  
17 rather than cutting it off in 2016. But changing the  
18 export pricing and the response to pricing brings a  
19 tremendous response on the export market, over 1,400 MW  
20 increase and about, between the Medium and High Cases,  
21 export market becomes 40 to 46 percent of the total  
22 market. In the High Case, which had a lot more onsite  
23 stimulation, there's a 1,700 MW increase compared to the  
24 Base Case on onsite market from the T&D support, the  
25 extended SGIP, and all of those measures. And there's

1 about maybe a 33 percent increase in the market  
2 penetration for the export market due to the focus on  
3 combined cycle technology and maximizing electric  
4 production, and also the impact of tax credits.

5 In terms of where the market is distributed,  
6 again, because of its geographical location in the  
7 businesses within its territory and, to a certain extent,  
8 the pricing levels, PG&E has 43 percent of the projected  
9 market penetration. And this is the Base Case.

10 While we were talking through the other charts,  
11 I talked a bit about the small vs. large CHP market and  
12 this table shows the breakdown for the three cases of  
13 market penetration between those three markets, below 20  
14 MW and above 20 MW for the High Cases, and I think I  
15 pointed out that the changes in the onsite and export as I  
16 was going through the charts. But I think the fact is  
17 that the two markets respond very differently to the  
18 incentive factors, the onsite market is very sensitive to  
19 the retail rate structure, gas and electric, and incentive  
20 factors with the SGIP, and cost and performance  
21 improvements. A lot of the smaller technology has more  
22 room for future improvements, it's more of an emerging  
23 technology, or at least the experience with packaging and  
24 installing. And Investment Tax Credits, T&D Support,  
25 those things all support the small market.

1           The large market is primarily an export market  
2 and, so, the number one, number two, and number three  
3 factor, I guess, are the export price and the conditions  
4 for export, but the market also responds to Investment Tax  
5 Credits and that.

6           So we calculated the GHG emissions savings. If  
7 I'm running long, I'm not going to try to go through this  
8 in a lot of detail, but basically a CHP system produces  
9 electricity which either avoids the need to generate  
10 electricity at the grid, or is fed back to the grid, and  
11 the impacts are shown in the lines there. In terms of  
12 avoided emissions for that added power, we used the ARB  
13 assumptions that were in the Scoping Plan, which was 963.4  
14 pounds per MW hour and line losses of 7.8 percent. Only  
15 the onsite markets are affected by line losses, it was  
16 assumed that the export market is fed back into the grid  
17 and it is subject to line losses, so the savings are a  
18 straight one for one with the utility generation rate.

19           And then the next thing is the impact of the  
20 added fuel use, which is the difference between the  
21 avoided boiler use and the added CHP use, and I've got a  
22 little formula there for how we calculate it. But this  
23 calculation, it goes on for each of the market sectors,  
24 the load factors in the model, the sizes, based on the  
25 performance of each of the individual systems. And it's

1 added up. But we compare it to the benchmark that ARB set  
2 up.

3           So the results show that, by 2020, the avoided  
4 GHG emissions range from 1.4 to 4.5 million metric tons,  
5 in 2030, it is gross 1.7 to 5.6 million metric tons. I  
6 probably should leave it at that, but we also looked at it  
7 in that this is compared to current situation. In the  
8 real world, everyone is going to be reducing emissions  
9 together, cap and trade, the utilities are going to be  
10 reducing emissions, so the actual emissions over time are  
11 going to be affected by the shielding effect that onsite  
12 CHP has in terms of avoiding the need to purchase  
13 renewable power systems at the utility. If their load is  
14 reduced by 100 megawatts and they're required to meet 33  
15 percent of their new load with renewables, then  
16 effectively 100 MW of CHP is avoiding the purchase of,  
17 say, 33 MW of renewable in the out years. So we looked at  
18 it in this way, I don't know if it's really fair to say,  
19 "Oh, well, CHP isn't meeting its goals." It's showing  
20 that the goals are being met and that the differentials,  
21 as you reach the target, get smaller and smaller.

22           The thing to point out is that export projects  
23 don't diminish the utilities' requirement to meet -- it  
24 doesn't diminish their capacity targets because it is  
25 considered their capacity, and so the GHG impacts of



1 exported emissions become part of the utilities' average  
2 emissions. And so the two higher cases where the  
3 emissions or the penetration is mostly -- or largely  
4 export -- half export -- then those don't come down as  
5 much. I know I'm behind --

6 CHAIRMAN WEISENMILLER: Yeah, why don't you just  
7 wrap up with this slide and then we'll take questions?

8 MR. DARROW: Okay. I think people can read the  
9 market penetration, or the conclusions that I have. If I  
10 can just maybe go to the last one, is that -- I don't want  
11 to lose site of the fact that the CHP does benefit  
12 customers individually and support California  
13 environmental goals. And the GHG emissions savings,  
14 depending on whether you calculate it one way or another,  
15 the focus, I think, should be on the cost-effectiveness of  
16 the benefit that's being provided, that a lot of  
17 technologies are being chosen to meet this sweeping goal  
18 through cap and trade, and CHP is helping to meet the goal  
19 and maybe the contribution is cheaper than some other  
20 alternatives.

21 And for individual customers in the Base Case,  
22 they're saving \$740 million a year in energy costs through  
23 this market penetration, and in the High Case, they're  
24 saving \$2.9 billion per year, so there's a private benefit  
25 and still public benefit.

1                   CHAIRMAN WEISENMILLER: Okay, thanks. You  
2 covered a lot of ground. Any questions?

3                   MR. NEFF: Are there any questions from the  
4 audience? Could you please approach the dais or the  
5 podium? Please state your name for the record.

6                   MR. SIMONS: George Simons with Itron. Ken,  
7 when you guys looked at the GHG emission benefits, you  
8 used the CARB numbers. Those are essentially carbon  
9 neutral goals. Did you look at the impact of CHP where  
10 you could actually get to negative GHG emissions?

11                  MR. DARROW: Um -- I would say no because I  
12 don't understand in the case of CHP, it's always going to  
13 have a certain fossil signature, what necessarily you mean  
14 be negative emissions.

15                  MR. SIMONS: Okay, so some of the analyses that  
16 we've done on the Self Gen Program, we found that it's a  
17 critical feature on the waste heat recovery side that, at  
18 best, when you're competing -- when CHP is competing  
19 against combined cycle, the only way it can go to a GHG  
20 negative position is through waste heat recovery, and  
21 increasing waste heat recovery, because 200 of the hours  
22 during the year are essentially on the peaking side, so  
23 the other vast majority of the number of operations during  
24 the year have to go up against these combined cycle very  
25 high efficiency plants; so the only way CHP can compete on

1 a GHG basis is to increase waste heat recovery. And we  
2 think that CHP can do that very successfully. Secondly  
3 is, did you look at both the NO<sub>x</sub> impact on GHG for oxidant,  
4 as well as the use of biogas for CHP?

5 MR. DARROW: Let me respond first to the  
6 original comment on GHG. Our systems with the heat rates,  
7 in each market we assumed a different thermal utilization  
8 and thermal recovery, and I guess our kind of net heat  
9 rates were running around 6,000, 6,100, a really super  
10 designed CHP system you could have a net heat rate in like  
11 the 4,500, less than 5,000. You're certainly going to  
12 beat a combined cycle plant that is operating around  
13 7,000, and then adding line losses to that. So I think,  
14 in that sense, I feel that the CHP systems that are  
15 focused on heat as a thermal recovery mode all beat the  
16 standard of a combined cycle power plant. In terms of the  
17 criteria pollutants and NO<sub>x</sub> emissions, we did not kind of  
18 maintain that tracking. We did, in building up the plant  
19 cost data, we included cost so that all these technologies  
20 met CARB '07 emission standards. But we have the ability  
21 to track criteria pollutants, but we really didn't update  
22 the performance of the technologies this time and we  
23 didn't really output that, so we didn't look at the  
24 output. And now I've forgotten the third question.

25 MR. SIMONS: It was about biogas.

1 MR. DARROW: Oh, biogas.

2 MR. SIMONS: Because of the methane.

3 MR. DARROW: Yeah, well, all types of CHP are  
4 included in the existing CHP analysis, but the market  
5 penetration is based on natural gas systems. We were not  
6 able to add biogas. In 2009, it was a separate study on,  
7 I guess, biogas opportunities, which might add I guess  
8 another 400 MW of potential in the state. But, no, we  
9 don't include the biogas or biomass in this estimate.

10 MR. SIMONS: Yeah, and in no ways do I want my  
11 comments to be a criticism of ICF, I think you guys did a  
12 great evaluation job, it's just that I think those are  
13 additional benefits that need to be taken into account  
14 because, again, some of the work that we've done, you  
15 know, because of the methane capture is such a powerful  
16 GHG emission reduction strategy, and because California  
17 has a lot of biogas, that has been underutilized, that  
18 should be worked into -- I think personally that should be  
19 worked into an analysis.

20 MR. DARROW: I agree. I mean, it's certainly a  
21 low hanging fruit, it's a hot market. The upside  
22 potential is fairly limited is all, I mean, in terms of  
23 strategic thinking, in terms of getting businesses going  
24 and getting projects underway, those markets are going  
25 very strongly.

1           CHAIRMAN WEISENMILLER: Yeah, it would be great  
2 if you could submit biogas analysis you've developed at  
3 Itron into our record here?

4           MR. SIMONS: Sure, absolutely.

5           CHAIRMAN WEISENMILLER: Thanks. Next.

6           MR. BARKER: Dave Barker with San Diego Gas &  
7 Electric. I just had a question about the categories  
8 Onsite vs. Export. Are you basically taking a facility  
9 and splitting it into onsite and export amounts? Or are  
10 the exports somehow different, or different facilities, or  
11 -- could you explain the difference, the categories?

12          MR. DARROW: We took the same facility and cut  
13 it in half and put half of it in one bin and analyzed it  
14 as an onsite market, and half of it in an export market  
15 and analyzed it as export. And I realize there's some  
16 potential pitfalls of doing that, but it was the easiest  
17 way to analyze it. We did essentially, you know, I would  
18 say we saw there was 10 MW of export potential as part of  
19 a total 60 MW project, we would still put that 10 MW in  
20 the over 20 MW export size bin, just to reflect the  
21 economics of large systems. But to analyze it with the  
22 different pricing, we ended up splitting them up.

23          CHAIRMAN WEISENMILLER: Thanks. Next.

24          MR. PINGLE: Hi, Ray Pingle from Sierra Club.  
25 So as I understand your report, you're saying there's

1 roughly 15,000 to 16,000 MW of technical potential CHP in  
2 the state. Is that correct? And that -- but even in the  
3 High Case, you're saying that there's a potential of 6,100  
4 MW, which would still be shy of the Governor's goal of  
5 6,500 MW? Am I understanding that correctly?

6 MR. DARROW: Yeah, I didn't call it "potential,"  
7 but market penetration, I look at the technical potential  
8 number is, I mean, you know, a BMW dealer could come to  
9 California and say he has a potential market of five  
10 million customers based on certain estimates of their  
11 income, etc. It's a long way from the technical potential  
12 to having an economic project and wanting to go forward  
13 with it, and that's why the numbers -- we're getting  
14 about, well, whatever percentage six over 16 is, and  
15 that's the High Case. So there is quite a lot of the  
16 technical potential that doesn't move forward, or is not  
17 likely to move forward as a project.

18 MR. PINGLE: So it sounds like we need to do as  
19 much as we can to create favorable conditions to realize  
20 the maximum penetration, and it sounds like there's a lot  
21 of savings that could help pay for some of those  
22 incentives, as well. Thank you.

23 MR. DARROW: Thank you.

24 MR. SCHWARTZ: Hi. Andy Schwartz from the CPUC.  
25 I had a question regarding -- more of a question or

1 clarification on Slide 18 where you talk about the  
2 sensitivity of the market opportunity for CHP owing to the  
3 CO<sub>2</sub> allowance price under cap and trade. It sounds like,  
4 based on what you presented, that on this slide, the cap  
5 and trade program actually has an adverse impact on the  
6 market opportunity of CHP. And I was just wondering how  
7 much of that is driven by the assumption that 90 percent  
8 of the revenue is returned through rates.

9 MR. DARROW: Well, I think, if going back to the  
10 slide, which I don't know if I can bring it up for  
11 everyone, oh -- I think if you compared the case where we  
12 had no electric reimbursement and said, okay, that's the  
13 new Base Case, then the reimbursement reduces the market  
14 by another 7.5 percent, so just to go here -- if there's  
15 no reimbursement, and this is your basis, and so the  
16 impact to reimbursement is -- sorry -- the impact is seven  
17 percent and then the impact of -- so the adverse impact is  
18 reduced from 18 to 11 percent.

19 MR. SCHWARTZ: Right, but again, just to be  
20 clear, so without a cap and trade program, according to  
21 this slide, you have 18 percent higher penetration CHP  
22 whereas --

23 MR. DARROW: Right, with the assumption that 90  
24 percent of the electric rates are reimbursed and none of  
25 the gas costs.

1           MR. SCHWARTZ: Okay, and so the assumption where  
2 there are no electric -- I'm just trying for clarification  
3 -- if there's no reimbursement under the cap and trade  
4 program, then the cap and trade program results in an 11  
5 percent increase in the market penetration of CHP relative  
6 to the Base Case?

7           MR. DARROW: Yeah, that would become the new  
8 Base Case, so you'd raise the floor up to that level.

9           MR. SCHWARTZ: Okay, thank you.

10          CHAIRMAN WEISENMILLER: Yeah, Ray. You'll be  
11 the last question.

12          MR. WILLIAMS: This is Ray Williams from PG&E.  
13 I just wanted to follow-up on some questions that Andy had  
14 asked, just so we're on the right slide here. So I guess,  
15 you know, from my simple perspective, in the wholesale  
16 markets, cap and trade costs will be reflected in  
17 wholesale commodity prices and, as part of the QF CHP  
18 settlement, which a number of us were very involved with,  
19 the compensation was structured so that it would increase  
20 once the cap and trade program came into play. So, in  
21 other words, on the export side, one would figure, given  
22 the fact that compensation will increase, as long as CHP  
23 generally is more efficient than the market, they actually  
24 should make out pretty well under either a low price or a  
25 high price scenario. Now, if CHP is less efficient than



1 the market, one might expect the opposite effect. So just  
2 looking at the low price and the high price, I'm a little  
3 confused relative to, you know, what I see in terms of  
4 where wholesale market prices are going, and looking at  
5 efficient CHP.

6 MR. DARROW: Well, I agree with you that the  
7 wholesale market is different and our assumptions, which I  
8 may have glossed over as I was moving forward, was that  
9 for the export market, the cap and trade does not affect  
10 the market or the pricing because there are mechanisms to  
11 capture the price in terms of who is responsible and that  
12 price is covered and it doesn't affect the return to the  
13 generator. In this particular, when we did it off the  
14 Base Case, which I mentioned was an 80 percent onsite  
15 scenario with very little export penetration, so what  
16 you're looking at is, I guess, the effect of the retail  
17 markets, which are strongly affected. And I agree with  
18 you that the export markets in our logic should not be  
19 affected much or at all.

20 MR. WILLIAMS: Right.

21 CHAIRMAN WEISENMILLER: Thank you. Ray, you're  
22 going to be on the panel this afternoon and one of the  
23 things, certainly, would be to dig into this more. I  
24 know, certainly, Cliff and I are both getting letters from  
25 a number of existing projects wondering what the impact of

1 this is going forward, but, again, pick up that more this  
2 afternoon.

3 Certainly, thanks for your presentation this  
4 morning, you covered a lot of ground. We appreciate  
5 getting that pretty broad framework for the subsequent  
6 panels. And hopefully you'll be around long enough to the  
7 extent that there are other questions, and that people  
8 have an opportunity to catch up with you.

9 MR. DARROW: Sure.

10 CHAIRMAN WEISENMILLER: Let's go on to the next  
11 panel.

12 MR. NEFF: Thank you, Ken. I do want to make  
13 aware that, as Ken mentioned during his presentation, that  
14 we're anticipating the draft version of the report on the  
15 27th, and that will provide the opportunity for people to  
16 submit written comments on the full report and the closing  
17 for comments is on March 9th.

18 So now we're going to focus on the Small CHP  
19 Panel, which focuses on the CHP market, and as Ken  
20 described, there are different drivers and different  
21 barriers for the different sizes of technologies. And  
22 through this process, we're going to try and identify what  
23 works and what doesn't through first hand experiences of  
24 both people who have installed CHP at their own  
25 facilities, and then some CHP manufacturers who have

1 installed it at other people's facilities and have had  
2 experience in the California market.

3           So we'll be starting with Sam Ruark from Sonoma  
4 County. He is the Project Manager there at the Local  
5 Government Partnership. He is a former Sustainability  
6 Planner for Marin County and has worked on sustainability  
7 initiatives in the nonprofit, small business, and local  
8 government sectors.

9           MR. RUARK: Thank you, Bryan. Good morning. Is  
10 everyone awake out there? All right. So, yeah, I'm Sam  
11 Ruark with Sonoma County, managing management of the  
12 Sonoma County Energy Watch Program. I'm going to talk  
13 about our comprehensive energy project which a key  
14 component of that was the 1.4 MW fuel cell that we  
15 installed.

16           Just to give a little context to our commitment  
17 to sustainability, within the past decade we have  
18 installed a turbine at our landfill to generate five to  
19 six MW of landfill gas. We have a robust local government  
20 electric vehicle partnership. The third line there is  
21 actually a typo, we don't have 820 MW of solar, that would  
22 be great, but we have 820 Kilowatt of solar within the  
23 county operations. We've got this new 1.4 MW fuel cell,  
24 we're looking at 1.1 MW of biogas development. Our Energy  
25 Independence Program has financed over 5 MW of solar, and

1 in the county as a whole, we have 50 MW of solar, we're  
2 actually averaged one MW per month being installed in  
3 Sonoma County right now. And my office is working on  
4 several different energy projects financed through Home  
5 Bill Financing, the ARRA funds, and Qualified Energy  
6 Conservation Bonds, and then my program, the Sonoma County  
7 Energy Watch, saves about five MW hours per year to all of  
8 our customers.

9           So in 2008, we decided we wanted to do a  
10 comprehensive energy project. We put out an RFP for an  
11 ESCO to assist us with this. We selected Aircon Energy  
12 and they did an investment grade audit of our facilities,  
13 they came up with 180 energy efficiency measures that we  
14 could do. We scaled that down to 101 measures. And then  
15 the process, once we got it to 101, we figured out, "Okay,  
16 what could we actually do? What can we take to the bank?"  
17 And overall, our objectives for the comprehensive energy  
18 project were cutting our greenhouse gas emissions to meet  
19 our goals set by our board, we wanted to have a positive  
20 financial impact, and we also wanted to remove some of our  
21 aging infrastructure in our County campus. A lot of the  
22 buildings there were built in the '50s, '60s, '70s, and  
23 some of them were starting to see some serious degrading  
24 of equipment.

25           So, the CEP or Comprehensive Energy Project

1 essentially became a project of 38 energy efficiency  
2 measures in 24 buildings, or 20 buildings, actually, with  
3 1.3 MW hours of savings. We did new motors and variable  
4 frequency drives on our HVACs, we did a major retrofit to  
5 our central mechanical plant, which feeds power and hot  
6 and cold water to 14 buildings on our County campus. We  
7 did water retrofits, saving 20 million gallons of water  
8 per year, we also installed an ozonator for our laundry  
9 facility. And the biggie -- the thing that really made it  
10 all happen and made it possible was the 1.4 MW fuel cell.

11           So the one we installed, here is a photograph of  
12 it, the stack is here on the left-hand side, essentially  
13 Fuel Cell Energy is the company that manufactured it, it's  
14 a molten carbonate fuel cell, DFC 1500, it essentially  
15 generates 10,693,000 KW hours per year, it also produces  
16 45 billion Btus per year. The great thing is it produces  
17 essentially no NO<sub>x</sub> or SO<sub>x</sub>, you know, it's designated clean  
18 by CARB, and it reduces -- when we modeled it, it showed  
19 that we reduced our greenhouse gas emissions by 69 percent  
20 vs. the grid power, primarily because we have a waste heat  
21 recovery unit on this fuel cell. As kind of a very middle  
22 of the top thing, you see the stack, and there's a pipe at  
23 the top, that's basically the cane unit that captures the  
24 waste to heat in order to offset the needs of our boilers  
25 to heat our buildings.

1           Most of you know how fuel cells work, so I won't  
2 go into this, but essentially it's natural gas, or biogas  
3 coming in, we use natural gas and water to create heat, to  
4 separate the hydrogen off of it, in order to create  
5 electricity. And then you've got heat and water as your  
6 byproducts. And I would love for Fuel Cell companies and  
7 manufacturers to one day create a system where it's closed  
8 loop so we're not having to feed water in and let water  
9 off, so there should be some way to capture that water  
10 eventually. It also creates DC power and then we convert  
11 it through inverse to AC.

12           Supposedly, I don't know if this is still true,  
13 but six months ago, it was the largest fuel cell in  
14 California at 1.4 MW, there's a lot of other entities  
15 looking at us on this particular fuel cell. You know, it  
16 is adjacent, is right at our central mechanical plant, so  
17 it is really perfectly situated. Essentially, it is 47  
18 percent electrical efficiency plus 20 percent due to  
19 combined heat and power. So, supposedly, it's compared to  
20 -- a fossil fuel plant is 33 percent, or those. And  
21 essentially there's no transmission losses because it is  
22 right out of a 12 KV loop; we can produce the power and  
23 feed it right in. It is powered by natural gas. We have  
24 looked at biogas, however, the biogas costs were too high  
25 for us, and it kind of screwed with our financing. One of

1 the key things that made it work for us was the SGIP.  
2 This project, you know, was a \$10 million fuel cell,  
3 essentially, and we got a \$3 million incentive through the  
4 SGIP.

5 The graph here is basically our load shape. You  
6 know, basically our demand at night is 850 KW, but in the  
7 peak summer it can go up to 2,500 KW, so you know, there  
8 are times, pretty much every day, where we are both  
9 exporting and importing power to and from the grid. Our  
10 electric annual utility bill for the County is \$1.5  
11 million, and you know, our natural gas bill did go up by  
12 \$350,000 per year based on all the natural gas we're now  
13 using for the fuel cell. However, we are through the  
14 whole Comprehensive Energy Project as a whole, we're  
15 reducing our utility costs by \$1.5 million per year. And  
16 the key thing to realize is the fuel cell payback was  
17 seven years.

18 This is a photograph of our board, Board of  
19 Supervisors, essentially they said, "We want you to do  
20 this, we want to continue to be leaders, but we can't put  
21 any General Fund money toward this, so you've got to make  
22 it cost neutral." So we looked at both private financing  
23 and Municipal financing via bonds, and the better interest  
24 rate came from the private market. And Banc of America,  
25 not Bank of America, I don't know what the difference is,

1 but they essentially were the ones that funded the  
2 project. And it was interesting timing, too, because we  
3 essentially starting going to the bank in December of  
4 2008, so at that time, getting a loan was tough, but we  
5 had really good clear investment grade audits to present  
6 and the bank received it, and after studying it for a  
7 while, they decided to loan us the \$18 million needed to  
8 do the project.

9           So, yeah, total project cost was over \$22  
10 million. We received almost \$4 million in incentives and  
11 grants and rebates, so we financed \$18.7 million. Our  
12 interest rate was 4.98 percent, we're going to pay it back  
13 over 16 years. We estimated the annual energy cost  
14 escalation to be 5 percent, we have positive first year  
15 cash flow at year 12. And so, essentially over the 16  
16 years, we're going to be paying \$31 million for this  
17 project; however, if you take it over a 25 year life,  
18 which is what we expect, we'll save \$38 million. So this  
19 is a positive cash flow project for us over the long term.

20           There's the check, \$3 million. Here is the  
21 graph showing the cost. We basically modeled it so that  
22 we save a little bit of money every year, and then at year  
23 12, it levels off, and then in the year 16, we're totally  
24 done paying for it. So it allows us to remain in that  
25 positive cash flow situation.



1           So based on how the project is modeled, these  
2 are what we're going to see. Now, we're in the process of  
3 the Measurement and Verification process, we are not  
4 actually getting the energy savings that were modeled by  
5 the ESCO, we are short of those by about 20 percent. And  
6 what we see is that we need to fine tune our operations,  
7 and so we're in a process of retro commissioning that  
8 right now, realizing there's times where the fuel cell is  
9 firing and we have hot and cold water both go into our 12  
10 KV loop, so why aren't we sending chilled water and hot  
11 water at the same time to the buildings, so being able to  
12 fine tune that is where we're at right now. However, if  
13 all of it gets fine tuned the way we can see it's  
14 possible, it will reduce our greenhouse gas emissions by  
15 6,135 tons per year, it will reduce our electricity use  
16 through the efficiency, and to the fuel cell by 13 million  
17 Kilowatt hours, we'll save almost 20 million gallons of  
18 water and we'll cut our utility bill by up to \$1.6  
19 million. And so basically we take that utility savings  
20 and pay back the debt every year, so we're continuing to  
21 get the same amount of utility budget every year, but  
22 instead of paying the utilities, we pay for the debt.

23           So the great thing is it had no general impact,  
24 like I said, it replaced some of our old worn out  
25 equipment, and really, you know, it helped create jobs and

1 collaboration and got the County to be able to walk its  
2 talk related to greenhouse gas emission reduction, cost  
3 savings, and cutting utility bills.

4           So here, this is the main slide, these are the  
5 challenges we have run up against. The first thing is  
6 that, when we were sold the fuel cell, we didn't realize  
7 we were working through our ESCO and we didn't really have  
8 direct communication with Fuel Cell Energy, which is we  
9 didn't realize that we could not have the fuel cell  
10 operate based on our load shape, and then, you know, we  
11 had already purchased it and it was already in the process  
12 of being built, and we realized, "Oh, this thing has to  
13 operate 24/7." And so we went to PG&E and we said, "Okay,  
14 we're going to have some excess power here, we want to  
15 connect to your grid." And we knew we were going to  
16 connect to the grid anyway, but we said, "We want to  
17 feedback some of this excess electricity into the grid."  
18 And they resisted. It took essentially four months of  
19 constant negotiation and trying and trying and trying, and  
20 finally they said, "Yes, we'll take it." At that time,  
21 1613 had already been passed, so we were waiting on being  
22 able potentially to get a tariff for that. There was this  
23 back and forth, as you all probably know, what the CPUC  
24 related to as FERC, or is it CPUC who makes a ruling on  
25 this, and then after several years it feels like finally

1 the CPUC has ruled on 1613 and we know what 1613 says.

2           So we have a combined heat and power facility,  
3 we export power to the grid, however, we've been denied a  
4 tariff. Essentially, PG&E tells us that the reason  
5 they're denying us a tariff is because of our SGIP, that  
6 we got that in 2010 budget cycle, and that we -- if we had  
7 gotten it in 2011, maybe we would be getting a tariff.  
8 However, as we read 1613, it doesn't say that we should be  
9 denied a tariff. What we export to the grid is very  
10 minor, we only export 5.6 or 6.0 percent of our  
11 electricity to the grid from what the fuel cell produces.  
12 That's only 600,000 KW hours per year, you know, at six  
13 cents per KW hour, that's only like \$36,000 or \$37,000, so  
14 it's not much. But if we could utilize that money through  
15 a tariff to do more energy efficiency projects, we would  
16 greatly benefit. So you know, we're reaching out to  
17 others, I've been in communication with Bryan Neff here at  
18 the CEC, we've been in constant contact with PG&E, we've  
19 heard different things from them. Part of their group  
20 says, "Oh, yeah, we can pay you," and then part of the  
21 group says, "No, we can't." So we're kind of in this gray  
22 zone right now. So any assistance that any of you can  
23 provide to that will be a great help.

24           And then just the last thing I'll say -- oh,  
25 PG&E stands up. Thank you!

1                   CHAIRMAN WEISENMILLER: PG&E is here to help.  
2   Why don't you finish up?

3                   MR. RUARK: Awesome. So I'm just going to say  
4   one more thing before I wrap it up and then Ray can go,  
5   which is -- so just on the technical issues related to the  
6   fuel cell, the only thing -- the stack itself is working  
7   great, we've had problems with our water filtration and  
8   the water filtration -- our water has more silk in it than  
9   it was tested at before the fuel cell was installed, so  
10  we're having to replace filters every week vs. every six  
11  months. And also, water consumption has gone up, and  
12  natural gas consumption has gone up. But, you know,  
13  there's been a couple other issues that have come and  
14  gone. And we also realized that whenever the fuel cell  
15  goes down in the middle of the day in the summer time, we  
16  get those demand charges. So we're asking Fuel Cell  
17  Energy, which they're complying with to do any maintenance  
18  that they have related to the fuel cell in the off peak  
19  times. So, with all that, that's my presentation, and I  
20  would love to have any checks or guidance from PG&E on  
21  this opportunity.

22                  MR. WILLIAMS: So, again, my name is Ray  
23  Williams, I'm from PG&E. I'm in the Energy Procurement  
24  side, so I generally deal with the large projects, not the  
25  small ones. But I did try to talk to some people who are

1 very involved with the SGIP Program. So I'm sort of  
2 reading off my Blackberry here, but essentially what I  
3 understand is that, when you signed up for the SGIP  
4 Program, at that time there were no grid deliveries as  
5 part of that program, so it's not really AB 1613, it's the  
6 way the SGIP Program was set up at the time. And so  
7 you've got -- PG&E is a Program Administrator and, you  
8 know, he himself is not authorized to be at variance with  
9 the rules that are in front of him based on when you  
10 signed up, so that's probably why it feels like kind of a  
11 stiff arm. And if you've talked to three or four  
12 different people at PG&E and you got different answers,  
13 then I'll try to deal with that. I think, though, going  
14 forward, exports are allowed in the new program, and so  
15 the natural question is can you apply that retroactively.  
16 And I think the answer is yes. But the process is you  
17 have to go back and petition the PUC to get a rule changed  
18 for that old program, and that should be relatively  
19 straightforward. And, you know, I talked to the program  
20 administrator for PG&E and we at least would support that,  
21 we would provide a letter of support for that.

22 MR. RUARK: Great.

23 MR. WILLIAMS: So I was able to get that much  
24 done in the last day or so, so hopefully get that petition  
25 in, we'll file the letter of support, and hopefully we can

1 take care of this.

2 MR. RUARK: Great, that would be fantastic.

3 Thank you very much.

4 CHAIRMAN WEISENMILLER: That would be good. I  
5 don't know, Andy from the PUC, any comment?

6 MS. KALAFUT: Jen Kalafut from the PUC. Yeah,  
7 and Ray is right, it's not the AB 1613 that puts any limit  
8 on what other programs you can participate in, but I'm not  
9 exactly sure or clear on the 2010 SGIP Program and where  
10 it says that exports are not allowed. And so I think it  
11 would be helpful if PG&E could point to the rules in that  
12 program specifically where they're interpreting that  
13 provision.

14 MR. RUARK: Great, thank you.

15 MR. RECHTSCHAFFEN: Sam, I had a question. You  
16 said that so far the savings are 20 percent less than  
17 predicted. How has that affected your financing? And did  
18 you have a Performance Guarantee with the ESCO that did  
19 the work?

20 MR. RUARK: We have a Performance Guarantee  
21 based on the energy savings, however, the contract was  
22 written before my time, but basically there's nothing in  
23 the contract that says they will pay us back if we don't  
24 meet those savings. Basically, the Performance Guarantee  
25 says if we don't meet the savings, they'll come in and try

1 to rectify it through some, you know, retro commissioning,  
2 things like that, which we're in the process of doing.

3 What was your first question again?

4 MR. RECHTSCHAFFEN: How is that affecting the  
5 bottom line, essentially?

6 MR. RUARK: The good thing is we have been able  
7 to do other energy efficiency projects through ARRA and  
8 through on-bill financing and such, and also we've seen  
9 significant cost savings based on natural gas prices going  
10 down, so for this year we're fine and we're probably going  
11 to be fine for the next few years, but if natural gas  
12 prices spike again, then we could see some issues.

13 CHAIRMAN WEISENMILLER: Okay and I had a  
14 clarifying question. When you talked about a seven-year  
15 payback, that was once you netted out the SGIP payments or  
16 the incentive payments?

17 MR. RUARK: Correct.

18 CHAIRMAN WEISENMILLER: Okay.

19 MR. RUARK: And that was based on a five percent  
20 electricity cost escalation from PG&E.

21 CHAIRMAN WEISENMILLER: Great. Thanks.

22 MR. RUARK: You're welcome. Any other  
23 questions?

24 MR. NEFF: Thank you, Sam. I'll ask you and the  
25 other panelists to come sit at the table and we'll move on

1 to the next presentation.

2           The next presenter is John Hake. He is an  
3 Associate Civil Engineer with East Bay Municipal Utility  
4 District in Oakland, California at East Bay MUD's main  
5 wastewater water treatment facility. He is a member of  
6 the Process Engineering Group with a focus on energy  
7 issues, power sales and purchases, efficiency and demand  
8 management.

9           MR. HAKE: Thank you. Good morning. My slides  
10 are going to be a little bit different from what the  
11 handouts are, I've added a few, but I'll try and get  
12 through those quickly.

13           So I'm here to talk about East Bay MUD's  
14 Combined Heat and Power Project, which includes a Resource  
15 Recovery Program and our new biogas turbine. So I'll  
16 start by talking about the Resource Recovery Program and  
17 the opportunity we saw there in terms of increasing our  
18 biogas potential, and I'll also talk about the new turbine  
19 that we just recently installed. This is -- we've  
20 encountered a number of challenges in proceeding with both  
21 these projects, and I'll end up with some recommendations  
22 about how we can -- maybe some specific policy  
23 recommendations for improving the potential for combined  
24 heat and power, specifically, in the waste water treatment  
25 plant sector.



1           So over the last decade or so, East Bay MUD has  
2   seen a decline in our wastewater treatment flows, which is  
3   providing us with some unused capacity. Some of this is  
4   due to water conservation, and also the migration of  
5   industry out of the City of Oakland, and some of the  
6   industrial wastewater flows. So what we've found  
7   ourselves with was some unused anaerobic digester capacity  
8   and, because we're also feeling some pressures on  
9   maintaining low -- or reducing the increase in water and  
10   sewer rates, we thought that we might be able to earn some  
11   additional tipping revenue and there was an opportunity to  
12   put high strength organic waste into our digesters to  
13   increase our biogas production.

14           So over 10 years ago, we started by accepting  
15   some of the waste that I show here in this slide. Most of  
16   these are liquid waste, however, we're also receiving  
17   solid food waste which was something we started in 2004,  
18   with the Energy Commission assistance, and we're always  
19   considering other possibilities. And here's a couple  
20   pictures of our solid liquid waste receiving facility in  
21   the upper left photo, which shows a food waste load being  
22   received, that's solid waste that we slurry and then pump  
23   into our digesters, but most of our waste comes in tanker  
24   trucks.

25           I've included this graphic from the staff paper

1 that was prepared by Commission staff and from -- I think  
2 it was part of the 2009 IEPR process, and I've included  
3 this because it's nicely aligned with the Resource  
4 Recovery Program at East Bay MUD. It shows the cumulative  
5 increase in biogas production and energy generation from  
6 accepting some of these wastes into digesters at  
7 wastewater treatment facilities for co-digestion. And  
8 East Bay MUD is accepting fats, oils and greases in these  
9 food processing wastes. Because we're located in an urban  
10 area, we don't take dairy manures, although there are  
11 other wastewater treatment facilities that do that. But  
12 this shows the increase in potential, and I think the  
13 Resource Recovery Program at East Bay MUD mirrors this.

14 So we've been able to substantially increase our  
15 biogas production, doubling it over the last 10 years, and  
16 there's a concurrent increase in our energy generation,  
17 and there's also an additional benefit of diverting these  
18 wastes away from landfills in most cases.

19 Over the years, as we increased our biogas  
20 generation, we found ourselves outstripping our capacity  
21 to generate electricity with our existing IC Engines and  
22 we were flaring gas for quite some time, and so in 2006-  
23 2007, we saw the opportunity to add to our generation, to  
24 be able to utilize this biogas and with a secondary  
25 benefit of increasing our onsite power reliability.

1           So in 1986, our cogeneration system was founded  
2 with three internal combustion engines and, in 2011, we  
3 completed construction of our new solar turbine 4.6  
4 megawatts, and it's been operational for a few months now.  
5 Here is a photo of our facility, both old and new, you may  
6 have driven by our plant as you approached the Bay Bridge  
7 Toll Plaza, so this might look familiar to you.

8           And one of the metrics that we use to measure  
9 the success of our program is how much of our onsite power  
10 demand can be met by generation. And before we started  
11 the program, I think we were a typical wastewater facility  
12 in that we were meeting about 40 percent of our onsite  
13 plant demand, and over the years, by increasing that, we  
14 couldn't get quite up to 100 percent, but we were  
15 consistently above the 80 percent over the last few years,  
16 and now with the new turbine, we're projecting that we  
17 will become a net energy producer and be in excess of  
18 serving our onsite loads.

19           So here are some of the challenges that we  
20 encountered in both the R2 Program and with installing the  
21 new turbine. The ones I've highlighted in red, I'll talk  
22 about in a little more detail on some of the subsequent  
23 slides. But it's not just a simple matter of throwing  
24 these wastes into our digesters, there are a lot of  
25 process impacts in terms of toxicity and stability. We

1 need to ensure that we continue to meet our wastewater  
2 discharge permit conditions. Some of these wastes  
3 introduce contaminants that might damage equipment. They  
4 also create new odors that we haven't smelled before, that  
5 we had to deal with, and new contaminants in our biogas  
6 that we also have to scrub and condition before we can  
7 fuel the turbine.

8           We have some of our competitors, meaning our  
9 neighboring wastewater facilities, are starting to look at  
10 what we're doing and so they're starting to accept some of  
11 these wastes, as well. So those are some of the  
12 challenges with respect to the R2 Program. But what I'd  
13 really like to focus on more here are some of the things  
14 related to our turbine installation. But I think maybe  
15 the main message I want to convey here is that, you know,  
16 the things that we're doing with the Resources Recovery  
17 Program we think is great and wonderful, but it's also  
18 very challenging and it's not business as usual for  
19 wastewater treatment facilities, at least not yet.

20           Our solid liquid waste receiving facility where  
21 we take these wastes was funded in part by a California  
22 Energy Commission grant that was awarded in 2002, and we  
23 completed construction of this facility in 2004 with a  
24 half a million dollars from the California Energy  
25 Commission, and that was a significant factor in our

1 decision to move forward with developing that facility.

2 We did not receive grant support for the turbine  
3 because, at the time that we were moving ahead with that  
4 project, turbines and engines and other combustion  
5 technologies were not -- the funding was not available for  
6 those at the time.

7 We upgraded our interconnections with our  
8 utility, PG&E, and this is a lengthy process, it starts  
9 with the design and ends with -- it doesn't end until  
10 construction is completed, so for us that's been a five-  
11 year process. It involves a lot of design reviews and  
12 testing, inspections, installation of a specialized  
13 transfer trip which involved coordinating with the AT&T  
14 for communication lines. So there were a lot of moving  
15 parts to the interconnection process. Fortunately, our  
16 PG&E Project Manager was very experienced and was able to  
17 guide us through this, but it is a very challenging  
18 process and a very costly one. Our interconnection  
19 upgrades cost us approximately \$1.3 million and, when I  
20 looked back historically at what we paid under our Special  
21 Facilities Agreement in 1986 when we installed our  
22 engines, at that time we spent \$23,000 in interconnection  
23 and upgrade improvements. So that's quite a substantial  
24 cost increase.

25 The coordination and scheduling can contribute

1 to construction delays and there are -- PG&E is a large  
2 organization, and we're dealing with a lot of different  
3 groups; fortunately, our Project Manager was very capable  
4 and helped shepherd us through the process, but there were  
5 times when we would have job site meetings and there would  
6 be over a dozen folks there from PG&E, so it was quite a  
7 lot of communication going on and, so, really on both  
8 sides of the interconnection process we are fortunate to  
9 have a very experienced Electrical Engineer to help us get  
10 through this process. But for smaller wastewater  
11 utilities, this could be quite burdensome.

12           One of the main challenges we see now with  
13 regard to funding -- and this is a self-financed project  
14 -- is the decline in wholesale power prices over the last  
15 few years. We were very disappointed in the recent CPUC  
16 decision that categorized all unbundled RECs in a Category  
17 3. We felt that, because we are in-state generation  
18 connected to a California Balancing Authority, that we  
19 really should have qualified for Category 1, and if we  
20 had, I think that it would increase the value of the RECs  
21 that we might sell for the power that we use onsite where  
22 the only way for us to monetize the value of that is to  
23 unbundle the REC and sell it.

24           Also, we've talked about SB 1613, the feed in  
25 tariff, we feel that it might be of some benefit if the

1 prices were administratively determined and specific to  
2 the technology. Right now, it seems to be based on  
3 natural gas pricing, and we're not certain that that's  
4 really reflective of the real value of some of these  
5 smaller renewable energy projects.

6           You know, based on the decline in the wholesale  
7 power prices and the decline in the REC value, that's  
8 greatly increased our project payback period over what we  
9 had estimated originally, so in 2007 we were thinking that  
10 our payback might be somewhere in the range of seven to 13  
11 years, but now we're thinking that payback is probably  
12 going to be more on the order of 15 years.

13           Transaction costs for surplus power sales can be  
14 high. For our engines, we had an existing Power Purchase  
15 Agreement with PG&E for the sale of as available power.  
16 Originally we sought an amendment to include the turbine  
17 under that existing contract. Ultimately that was denied  
18 in favor of the new family of QF Agreements which is now  
19 coming out under the Settlement Agreement, and we were  
20 told to wait and do that, you know, at the time the  
21 settlement went through. So, currently, we have no way to  
22 sell surplus power for the turbine. I mean, we understand  
23 that there are a lot of alternatives out there, we'll be  
24 looking at the new QF Agreement, as well as other  
25 alternatives, but for -- we're a wastewater utility that's

1 primarily focused on onsite generation, so for us the one  
2 or two extra megawatts that we sell, and if we're trying  
3 to do that on a wholesale market and dealing with CAISO  
4 issues, and scheduling coordinator requirements, for many  
5 of you that may be things that you're very familiar with,  
6 but for those of us at a wastewater facility, this is kind  
7 of new terrain for us and it's not always easy for us to  
8 kind of sort out how we should sell the little surplus  
9 that we have.

10           And so, mainly the recommendations that we have  
11 looking ahead and, again, this is from the perspective of  
12 a wastewater utility, is the grant funding is very helpful  
13 in terms of us deciding to proceed forward with projects.  
14 The interconnection process, to the degree that can be  
15 streamlined and simplified would be wonderful. And then,  
16 in terms of stabilizing the revenue that we can expect to  
17 receive for this renewable power in the future, things  
18 like the REC value and firming that up, maybe putting some  
19 of these unbundled RECs in Category 1 where we think they  
20 belong, as well as tiering the feed in tariff to reflect  
21 the value of renewable energy, we think, would help to  
22 stabilize revenue and make it easier, provide a little  
23 more certainty to facilities like ours as we decide to  
24 proceed with these projects.

25           One proposal that we have was to put together a



1 program for biogas specifically, similar to what was done  
2 for the California Solar Initiative. So what that might  
3 involve is dedicating funding for grants specifically for  
4 biogas development, and also the feed in tariff and having  
5 a specific one that addressed biogas. And so this might  
6 apply not only to wastewater treatment facilities, but  
7 landfills and dairy digesters, as well.

8           We think there's a lot of additional value to  
9 biogas as a renewable energy source because it's not  
10 intermittent, it could serve as a baseload renewable, and  
11 you know, potentially provide peaking power if there's  
12 funding for storage, and it's eliminating a potent  
13 greenhouse gas, methane in particular. So that concludes  
14 my presentation and I guess if there's time I can take  
15 some questions.

16           CHAIRMAN WEISENMILLER: Yeah, thank you very  
17 much. I wanted to just understand your interconnection  
18 situation better. What voltage level are you  
19 interconnecting? I assume it's distribution level?

20           MR. HAKE: Primary at the 12 kilovolts.

21           CHAIRMAN WEISENMILLER: Okay. And so you've  
22 been doing this under the Rule 21 process?

23           MR. HAKE: That's correct.

24           CHAIRMAN WEISENMILLER: Okay. And what were --  
25 in terms of, you must have gotten some -- what was the

1 biggest -- so you had the \$1.3 million in cost, and also  
2 the five years in time -- what were the big elements in  
3 the time element and what was the biggest cost element  
4 when the interconnection equipment had to be done?

5 MR. HAKE: Well, in terms of the time element, I  
6 think -- I'm not sure that we can shorten the process if  
7 we're talking about taking a project through the whole  
8 lifecycle of design through construction, but I think  
9 where there was uncertainty between our contractor and  
10 ourselves in the utility was how to schedule certain  
11 inspections during the construction process. So it seemed  
12 sometimes difficult to us to get PG&E to be firm on  
13 certain dates when they could be available for inspection,  
14 and then, you know, with construction delays and  
15 everything, it's always this dance of trying to get things  
16 to align so that we could ensure that the inspection could  
17 proceed as scheduled. And then, in terms of the cost, I  
18 think one of the main elements there was we installed a  
19 direct transfer trip and, so, my understanding is that  
20 involved some additional communications that was needed in  
21 order for that trip to function, and so I think that was  
22 one of the main cost elements. About half of the cost was  
23 one time capital funding, and the other half of the cost  
24 is the ongoing O&M cost of like a one-time payment in  
25 perpetuity.

1           CHAIRMAN WEISENMILLER: And I was just going to  
2 make one observation and then I'll turn it over to Cliff  
3 in a second, is that there are companies that basically  
4 take on the role of scheduling coordinator for your type  
5 of situation, I don't know if there are any in the room,  
6 or certainly staff may be able to connect you with someone  
7 because it would be pretty daunting to go through the  
8 process to become a Scheduling Coordinator yourself, and  
9 obviously there are fees involved and various  
10 qualifications on those companies, but that may be the  
11 simplest route for you going forward.

12           MR. HAKE: Yes, thank you.

13           MR. RECHTSCHAFFEN: You said that the payback  
14 period has been lengthened because of the PUC's treatment  
15 of the RECs associated with the project, and I'm wondering  
16 what price did you assume the RECs would be sold at when  
17 you did the financing assumptions.

18           MR. HAKE: Well, to be clear, it's not solely  
19 because of the treatment of the RECs, I mean, the  
20 wholesale energy price decline is part of that, but --

21           MR. RECHTSCHAFFEN: Right, you said one of the  
22 factors.

23           MR. HAKE: -- but one of the factors is the RECs  
24 and so at the time we did the original cost calculations  
25 in 2007, we were thinking that we might receive a

1 wholesale power -- we might receive a power price of  
2 between \$.9 to \$.13 a KW hour, including the REC, which I  
3 thought at the time was a conservative estimate, was about  
4 \$.1 for a REC. And now we're seeing something much less  
5 than that, I think, for these unbundled RECs.

6 CHAIRMAN WEISENMILLER: Yeah, I was also going  
7 to note that the PUC has now proposed -- PUC staff EPIC,  
8 which would be sort of an ongoing renewable R&D program,  
9 and there are elements in that for biogas, and so  
10 certainly to the extent that East Bay MUD is supportive of  
11 those, I think that would help the PUC in certainly going  
12 forward.

13 MR. HAKE: Okay, thank you.

14 CHAIRMAN WEISENMILLER: Thank you. Any other  
15 questions from the audience?

16 MR. NEFF: Thank you, John. Next up is Bill  
17 Martini. Bill Martini is the Western Vice President of  
18 Sales for Tecogen. He is responsible for marketing  
19 Tecogen's ultra-efficient cogeneration and chiller product  
20 lines in California, but his territory also includes the  
21 Western U.S. and Canada, Mexico, and Asia. Bill  
22 represents Tecogen directly to hospitals, schools, and  
23 colleges, government buildings, and industrial facilities,  
24 performing detailed economic feasibility analyses for  
25 customers, and assists in managing their installations and

1 long term service needs.

2 MR. MARTINI: Thank you, Bryan and  
3 Commissioners, and all the experts in the room. We are  
4 representing a smaller end of the spectrum -- in the ICF  
5 Study this morning you saw some analysis of commercial  
6 facilities typically under 500 KW, or under one MW.

7 This is a typical 100 KW type system, it's an  
8 engine in a box with fancy emissions controls, a  
9 generator, an inverter on the end, and so on. Basically,  
10 the numbers on the right show that, if you put 100 units  
11 of fuel in, you get a certain amount as electricity and a  
12 larger amount out as hot water, so the total efficiency  
13 when you're recovering all the available waste heat is  
14 about 82 percent on a higher heating value basis, or  
15 sometimes people use lower heating value when they talk  
16 about efficiency, which would be over 90 percent. This is  
17 what the systems look like, about the size of big desks.  
18 This is another one, that's in a Community College in the  
19 East Bay.

20 Typical applications are the nonprofit sector,  
21 so hospitals, schools and colleges, places that are  
22 residences, so that includes nursing homes, retirement  
23 residences, apartment buildings, condos, dorms, hotels.  
24 And then recreation facilities, so that could include  
25 athletic clubs, Ys, City pools, JCCs, and so on.

1 Basically, these are applied where all the energy can be  
2 used behind the meter, so we're not trying to sell  
3 electricity back to the grid, typically. All the heat is  
4 at the same time used for heating domestic hot water,  
5 space heating, or spas and Jacuzzis and swimming pools.

6           So when you do all that, the sweet spot, you can  
7 get a very high efficiency that, even though they're very  
8 small modules, no economies of scale going on here, they  
9 can be far superior in terms of overall efficiency  
10 compared to a combined cycle plant. That's where the  
11 greenhouse gas savings come from.

12           There's been a lot of technology advancement in  
13 the last few years and this is a picture of somebody in  
14 the room here, in fact, Bob Weisenmiller. Some of the  
15 things that have advanced the technology in the small end  
16 include different kinds of certifications for  
17 interconnection, we've got those for Europe, for New York  
18 State, California, nationwide, different all sorts of  
19 crazy certifications. In addition, this inverter-based  
20 micro-grid compatible module was developed in part with  
21 CEC support. There's some advanced engine work that's  
22 ongoing right now at the CEC and, then finally, extremely  
23 low emissions that are comparable to, say, a fuel cell,  
24 from an engine which is unusual, not what people normally  
25 perceive. And I think over time that mindset will shift.

1 But we appreciate the CEC's support and proud to say  
2 they're actually getting some royalties from their  
3 support, so....

4 A typical savings, you've seen this kind of  
5 graph before, but basically from the owner's perspective  
6 who puts this in, our systems are all privately financed  
7 out of capital budgets, school district budgets, they can  
8 save a third to even up to half for the energy that these  
9 systems make, they can save that much relative to the Base  
10 Case, which is just buying a bunch of electricity and a  
11 bunch of gas for their boilers from the utility.  
12 Obviously, it's because of the waste heat that makes that  
13 possible.

14 Similarly, the greenhouse gas savings -- and  
15 George from Itron alluded to this -- as long as you use  
16 the waste heat, that brown box there is the boiler gas  
17 use, the red box is the gas used at the PG&E power plant,  
18 and then the blue is the stuff that would instead be used  
19 onsite to make that same amount of energy. So there's  
20 good greenhouse gas savings potential as long as you're  
21 using the waste heat. If you look at, say, 100 units of  
22 ours in the Bay Area, and I know other manufacturers have  
23 similar systems, they're running about 90 percent of the  
24 time without any other means to dump the waste heat,  
25 except put it into the pool, or put it into the building

1 for space heating. So these are real live efficiency  
2 calculations.

3 This is just a diagram that shows the current --  
4 the emissions from an engine. On the right is traditional  
5 BACT, traditional emissions requirements for NO<sub>x</sub> and CO.  
6 On the far left is what emissions look like from the newer  
7 systems, you'll be hearing more about this, I think, in  
8 the afternoon. In the middle are some published NO<sub>x</sub> and CO  
9 numbers from fuel cells. So pretty similar, pretty  
10 similar.

11 I think one little pitch for smaller systems is  
12 that they can offer pretty good cost-effectiveness.  
13 There's not a huge SGIP incentive, there's not a huge  
14 capital outlay required by the site, we're kind of doing  
15 things the old-fashioned way here. And if you look at the  
16 amount of potential greenhouse gas reductions available  
17 from small engine CHP systems, you know, you get a lot of  
18 bang for the buck.

19 So I'm going to follow the questions that Bryan  
20 had sent us ahead of time that he wanted to be sure we all  
21 touched on. First, what motivates end users to put in  
22 these little things? Typically, a payback less than four  
23 years is going to be required. Right now, you'll still  
24 find some applications in that range and there are some  
25 brave folks who can tolerate a longer payback. But to



1 have any kind of meaningful mass market, you're going to  
2 need a pretty good economic return. You obviously also  
3 need an excellent use of the energy onsite, so keeping the  
4 electricity on the customer side of the meter, not getting  
5 involved with the export as much as we think it would be  
6 handy at times, it doesn't look like the Regulations are  
7 going to be working out very positively for smaller  
8 projects, at least. Other things that influence owners'  
9 decisions, I think, is the level that they perceive of  
10 utility and government support. They want to be good  
11 citizens, they want to be good to the environment. If  
12 they can get a rebate check, whether it's \$500 million or  
13 \$5.00, it makes them feel better to feel like they're not  
14 fighting City Hall, so that's why I put it in italics. I  
15 think sometimes the levels of support -- symbolism is  
16 important here, too.

17 But they won't do a four-year payback if it's  
18 tough to implement, so what we found is that last item has  
19 kind of been one of the bigger challenges, and I'll be  
20 talking more about that.

21 Small CHP systems -- and I think, again, by  
22 "small" I'm referring to say under a megawatt system, and  
23 I think looking at ICF data of technical potential from  
24 earlier, it's about maybe a fifth or a quarter of the  
25 total 15,000 to 16,000 megawatts of technical potential

1 out there. So the systems are small, but it's about a  
2 quarter of the projected technical potential that ICF was  
3 mentioning. So what happens in smaller projects is a lot  
4 of transaction costs per kilowatt hour, and these fees.  
5 And I just want to highlight the ones that I think have  
6 added a couple years to the payback.

7           These didn't necessarily exist 20 years ago,  
8 it's interesting to note. Departing Load Charges, what we  
9 also call Exit Fees, pretty much gobble up a penny and a  
10 half of the customer's benefit. So what you heard this  
11 morning about the customer trying to utilize energy behind  
12 the meter is only able to impact about half or two-thirds  
13 of the electric rate because of these sort of gotchas.  
14 Those Departing Load Charges, a customer who installs an  
15 energy efficient pump, or remembers to turn off the light  
16 switch every day, or puts in a solar system, they don't  
17 pay those Departing Load Charges, they have identical  
18 profiles as far as the PG&E meter is concerned, but they  
19 don't get whacked with these charges, so it's kind of --  
20 it doesn't seem like a level playing field to us.

21           Similarly, with Standby Charges, customers who  
22 run following thermal load 95 percent of the time, that  
23 five or six percent of the time that they might be down  
24 because the pool is hot, is already up to temperature, we  
25 just thermally load follow, turn off, the customer pays a

1 demand charge that month, but in addition, on that same  
2 kilowatt, has to pay a stand-by charge. And to us, that's  
3 something that other technologies don't have to pay. The  
4 underlying rationale that we've kind of accepted in  
5 California for years, I think, deserves a second look.

6           Interconnection is still a challenge. The new  
7 SGIP came out with a program for a very small rebate for  
8 engines and turbines. At the smaller sizes, the metering  
9 and monitoring requirements of that program, it appears to  
10 us, is going to consume half to the full amount of the  
11 incentive, which does take away a little bit of the fun.  
12 And so I think there needs to be some size  
13 differentiation. There are practical solutions that we've  
14 offered comments on and we're hopeful some of that will  
15 get fixed.

16           Net Energy Metering down at the bottom there is  
17 a benefit that a lot of DG technologies receive, but CHP  
18 does not qualify for Net Energy Metering, and we're not  
19 talking about the laws of thermodynamics here, this is  
20 just arbitrary Regulations. And that can be changed. And  
21 that would be a big help.

22           Rules are very complex. This is just a chart we  
23 received from a helpful utility that was showing us how  
24 the different types of charges might apply to different  
25 types of technologies -- megawatts, technology, when it

1 was installed, what the fuel was, you name it. But I said  
2 it's about as simple as a third-world bus schedule.

3 Another side issue that the CEC in the past has  
4 been very helpful on was Rule 21. The CEC at one point, I  
5 think maybe for budget reasons, kind of considered that  
6 mission completed, mission accomplished, to coin a phrase,  
7 and that was then transferred to the PUC where there is  
8 now a pretty involved process going on that we're  
9 participating in when we have a spare moment.

10 One important thing that has kind of fallen off  
11 the back of the truck here is that CHP systems that are  
12 small need certifications to not get killed trying to put  
13 them in, not spending six months of your life on each  
14 project meeting with PG&E people. So a certification is  
15 an important thing. Smaller systems, there were a bunch  
16 of smaller systems that, in the earlier era, were  
17 certified under Rule 21, and that qualified them for what  
18 was called simplified interconnection. But that process  
19 doesn't exist anymore, so it's kind of Catch 22, the CEC  
20 maintains a list of certified inverters on its website,  
21 but that's only renewable certified inverters, as if the  
22 inverter knows the difference, as if the utility  
23 interconnection design team really -- the electrons are  
24 the same, whether there's an engine behind it, a turbine,  
25 or a solar panel. But you can't get certified. So we

1 feel that we would like the CEC to allow non-renewable  
2 inverters to get certified the same way that they used to  
3 be able to.

4 I mentioned this just a little bit, but  
5 different technologies get all these special perks and the  
6 CHP seems to be coming up a little short on some of this  
7 stuff, and if the State wishes to have 6,500 megawatts of  
8 new CHP 20 years from now, leveling this playing field  
9 would be a real help. So I'll just whip through them, but  
10 there's exemptions for standby chargers, there's  
11 exemptions from departing load charges, there's  
12 eligibility for net energy metering, there's a practical  
13 feed in tariff that's not excessive and have a lot of  
14 ambiguous requirements for really small projects,  
15 interconnection fees that CHP has to pay that other  
16 technologies don't, and then finally, the SGIP incentives  
17 are really really quite different.

18 I'll just compare two DG technologies here.  
19 This is in both cases, it's a 100 kilowatt system  
20 consuming natural gas, it's got a natural gas meter parked  
21 next to it, both making very comparable NO<sub>x</sub> emissions, so  
22 those are apples and apples up top, and then if you  
23 compare other qualities of the technologies, one has --  
24 maybe is making just electricity without waste heat  
25 recovery, high efficiency, maybe around 49 percent

1 depending on what math you're using, on the right would be  
2 a CHP technology where it's also recovering some waste  
3 heat. Both offer some greenhouse gas emissions reduction  
4 potential, depending on what you're assuming for the  
5 offset boiler and offset utility grid. Then there's the  
6 cost for the 100 kilowatt unit, maybe 130,000 on the right  
7 vs. 700,000 on the left. So those are like real numbers  
8 with the curtain pulled back.

9           Down below you'll see that they experience very  
10 different regulatory treatment. The technology on the  
11 left gets a much higher incentive, it's eligible for a big  
12 tax credit, as well, gets net energy metering, and  
13 exemptions from departing load standby, and so on. Small  
14 systems like ours don't get any tax credits, they're in  
15 nursing homes and hospitals, high schools, so I would say  
16 99.9 percent of our systems don't get any tax credits.  
17 But this is kind of a -- to us, the State is going to get  
18 what it incentivizes, but it won't get as much when it's  
19 paying a little more than it has to.

20           As a general rule, we would support creation of  
21 a level playing field and then letting the market sort of  
22 sort itself out. I think what's happened is people --  
23 companies with good lobbyists have kind of gone directly  
24 to the Legislature and kind of worked out special deals.  
25 I see, having been an engineer in this business for over

1 20 years, I see more and more of our industry's time  
2 focused on selling things to Regulators and Legislators  
3 instead of doing actual energy engineering in people's  
4 basements. And I think that's kind of a loss for the  
5 State. I think what I call picking winners, I think a  
6 Legislator wants to have a nice green press release and a  
7 photo op, but it ends up being -- creating for some  
8 strange and confusing regulations.

9 I think the ultimate issue is that, for  
10 taxpayers and ratepayers, you want to deliver the most  
11 bang for the buck, and if you follow these sort of  
12 arbitrary preferences, sometimes you end up with an  
13 inefficient allocation of those resources.

14 So my conclusion would be just, over the long  
15 haul, I think we need to phase out these departing load  
16 charges that we don't see in other states and that we  
17 think really are unjustifiable relative to all the other  
18 technologies, efficiency technologies that customers look  
19 at, standby charges, net energy metering, it would be nice  
20 to have SGIP get a little more rational and be extended  
21 because it's probably going to go poof before a lot of  
22 projects are able to go in. Thank you very much. I'm  
23 available for questions after any time.

24 CHAIRMAN WEISENMILLER: Thanks. Again, let's  
25 talk about your experience on the interconnect, in terms

1 of ways of trying to speed that up. Is the Rule 21  
2 reforms going to do it all? Or how does that fit with  
3 certifying the inverters?

4 MR. MARTINI: I think the -- well, the Rule 21  
5 reforms that are undergoing this settlement process thing  
6 at the PUC, which only companies, you know, it's two  
7 meetings a week, it's not practical for a lot of people --  
8 there's been very little CHP participation in that, it's  
9 interesting. I don't think it's going to solve the issues  
10 that I brought up. The certification, thankfully, the  
11 certification provisions that were in there, that were  
12 hard fought under the CEC's supervision, under the former  
13 Rule 21 Working Group, the guts of that mostly is still  
14 going to be retained, there's still some -- many aspect of  
15 the simplified interconnection and that we're going to  
16 deal with just three paragraphs out of the whole bill, the  
17 whole new rule. But I think the main Rule 21  
18 modifications are related to export systems and  
19 renewables, it seems like everything else is going to be  
20 kind of kept the same.

21 CHAIRMAN WEISENMILLER: Thanks a lot, Bill.  
22 Sure, go ahead.

23 MR. KUBBASEK: Thank you. Justin Kubbasek.

24 CHAIRMAN WEISENMILLER: Actually, if you have a  
25 question of him, otherwise we still have one more speaker.



1 MR. KUBBASEK: I do have a question for him.

2 CHAIRMAN WEISENMILLER: Okay, great.

3 MR. KUBBASEK: So in your experience, how  
4 aligned is customer payback with GHG reduction savings? I  
5 guess by that I mean the higher GHG reducing more optimal  
6 projects are also -- have a higher payback for their  
7 customers?

8 MR. MARTINI: I would say in general, yeah,  
9 that's true.

10 MR. KUBBASEK: Okay, so then I guess as a  
11 follow-up, I would be thinking, as we extend benefits or  
12 subsidies towards this market, then we shouldn't be  
13 looking at the most optimal projects, then, as  
14 representative of what we might expect by lowering or  
15 reducing the payback rate for projects that otherwise  
16 would be out of the money?

17 MR. MARTINI: I'm not sure I fully understand,  
18 but I think in general I would say you should look at how  
19 much benefit in terms of greenhouse gas reduction you can  
20 get for the investment. If the customer is going to do it  
21 anyway, then maybe you don't need to do much in the way of  
22 an incentive. But I think you want to -- but the reality  
23 is these extra fees right now are causing paybacks to be  
24 well over four years for a lot of smaller projects, and so  
25 you're not seeing a lot of activity, just a bare trickle.

1 MR. KUBBASEK: Thank you.

2 CHAIRMAN WEISENMILLER: Thanks.

3 MR. NEFF: Thank you, Bill. I forgot to mention  
4 earlier on East Bay Municipal Utility District's  
5 presentation, if anybody was interested in the wastewater  
6 treatment plant's potential in California that study is  
7 available online and the publication I.D. is on the bottom  
8 of that slide, Slide 6. I'm pretty sure Joe is happy to  
9 see his technology represented in that presentation.

10 Joe Allen is the Director of Government  
11 Relations at Solar Turbines, Incorporated. Mr. Allen is a  
12 Board member of the 2012 Chair of the Washington, D.C.-  
13 based U.S. Combined Heat and Power Association. He also  
14 sits on numerous other Boards, including the Board of the  
15 Business Council for Sustainable Energy, the American  
16 Uzbekistan Chamber of Commerce, and the Sustainable  
17 Development Advisory Board of the Rochester Institute of  
18 Technology.

19 MR. ALLEN: Good morning, everyone. And thank  
20 you very much, Commissioners, for inviting me, and thank  
21 you, Bryan. I'm going to keep this really short. I know  
22 we've got a lot of great information that's been  
23 presented. I'm very fortunate to be fourth on a panel of  
24 three other very qualified people, and you've heard some  
25 great summaries of the challenges that the marketplace is

1 facing in CHP in California.

2 I want to take a minute first, most of you know  
3 Solar Turbines and who we are. As Bryan mentioned, East  
4 Bay MUD actually has one of our machines in operation  
5 there. But I think in the spirit of full disclosure, our  
6 name is always confusing when we're talking about the  
7 energy world. I spend half my time talking about what is  
8 a solar turbine and how do we get the sun to spin that  
9 thing. And the reality is we love the solar industry, but  
10 we aren't in the solar industry. The original company,  
11 we're based in San Diego, it was formed in the 1920's as  
12 the Prudden Bay San Diego Airplane Company, and then  
13 became Solar Aircraft. And that company didn't build  
14 planes very long, but it did have kind of a unique history  
15 of building the Lindbergh Plane. And that was built in  
16 the building if, when you land in San Diego and you see  
17 our facility at the end of the runway, that's where that  
18 plane was built and that's where our facilities are, our  
19 main manufacturing facility is today.

20 The company evolved into an industrial gas  
21 turbine company and was renamed Solar Turbines,  
22 maintaining the solar name and I was going to have a  
23 lottery on where did the solar come from, well, the solar  
24 came from the fact that it's sunny in San Diego, and they  
25 called it Solar Aircraft back in the late '20s. So that

1 was the genesis, so we were solar before solar was  
2 popular, and we compare it to -- if you think of us as  
3 solar turbines, think of Apple Computers, they're not  
4 about apples and we're not about solar. They're about  
5 computers and we're about turbines. So that's for those  
6 that weren't familiar with some of the history, I wanted  
7 to just take a second and go through that.

8           Our company overview, we are natural gas and  
9 renewable fuel gas turbines. You saw a great example and  
10 a really nice presentation of a renewable fuel turbine,  
11 one of our Mercury 50s, at East Bay MUD today. We are a  
12 subsidiary of Caterpillar, we're wholly owned by  
13 Caterpillar, which is obviously -- I think a lot of you  
14 know who they are, they make the big yellow bulldozers and  
15 machines. A lot of people don't know that about a third  
16 of Caterpillar's overall portfolio is directed at the  
17 Energy industry in providing products that produce power,  
18 and with solar turbines being a big chunk of that. At  
19 Solar Turbines, we have around 7,500 employees with 4,000  
20 of them in California, and we build all the turbines in  
21 California, so we're sort of a unique manufacturing entity  
22 these days. And we do export about 70 percent of our  
23 products out of the U.S. and, unfortunately, the ones that  
24 are in the U.S., not that many of them are going in in  
25 California, and some of that is because of some of the

1 barriers that we're seeing. Our size range is in the one  
2 to 22 megawatt size, sort of our sweet spot is four to 15  
3 megawatts is where you see most of our units going in.  
4 Key markets are power generation, but we also serve the  
5 oil and gas industry. We have global population of 14,000  
6 units. Unfortunately, we don't have enough of those in  
7 California and we do have over almost a billion and a half  
8 operating hours.

9           I wanted to take a minute and, instead of going  
10 into specific case studies, etc., I wanted to really look  
11 at -- I'm trying to do a little summation on what  
12 customers are telling us and what we're seeing from a  
13 deployment standpoint related to California. And if you  
14 look at the base clean energy goals of the state, I put  
15 these four here, it's much more extensive than that,  
16 obviously, but obviously the key clean energy goals of the  
17 state align almost dead on with what the benefits that  
18 combined heat and power can provide. The big trick is,  
19 how do you get the regulatory regime and the markets in  
20 place to make sure that you have competitive markets  
21 delivering the right results to the ratepayers.

22           So to do this in a simple way, we just put  
23 together the report card. So if the customer is the  
24 parent and the student brings home the report card, this  
25 is sort of what they're telling us is happening, and

1 again, this is not statistically valid data, this is  
2 fairly subjective in what we're hearing, so I did want to  
3 mention that, and I'll take just a second and go through  
4 each one of these to give just a little background. But  
5 the thing is, all of the items that you're going to hear  
6 have been discussed very well by the three panelists here,  
7 by ICF, and by others. The interesting thing is, there  
8 aren't a lot of unknowns in this whole discussion, and  
9 everybody involved in this, that the big trick is how do  
10 we get the policies right so that you have a marketplace  
11 that can function and deliver the results that the  
12 ratepayers are frankly asking for.

13           And if you look in the overall report card, a  
14 grade of C, clearly the customers don't see that as  
15 acceptable and I think the Governor would not see that as  
16 acceptable and would see that there's some opportunities  
17 to do much better, that it's been very clear the  
18 leadership of the State has said, "We're going to be the  
19 A+ state." And I think it's heading that way, we're  
20 starting to see significant signs, but right now I don't  
21 know that the state is there.

22           So, very quickly, if you look at a few of these  
23 items, AB 1613, that has been a very positive policy  
24 initiative and, frankly, just some good policy in how it  
25 was put together. Sizing systems with thermal load is

1 logical. Being able to export if you have some excess  
2 makes sense. It took too long to do it and there are some  
3 other challenges in there, but I think overall what we're  
4 hearing and, you know, what we're seeing on the ground,  
5 that's the type of thing that adds value.

6           The SGIP, again, a very good program. You know,  
7 reinstate natural gas CHP, you know you're seeing our  
8 sales guys are saying they're starting to get interest  
9 that flat wasn't there before, so it is driving awareness  
10 again. There is, as we've heard, seems to be a preference  
11 towards advanced technologies vs. just greenhouse gas  
12 reduction. I think, you look at CHP as an industry  
13 doesn't want anything special, it just wants to make sure  
14 that there's a level playing field.

15           The last one here on no recognition of customer  
16 CHP value to the grid, you know, no recognition is  
17 probably too strong a wording, but it really is what we're  
18 hearing from customers is, hey, I'm on the customer side  
19 of the meter, I have these investments in place, and they  
20 do provide value, and they're a significant value from a  
21 capacity, reliability and grid congestion, and I really  
22 can't see -- it's not clear, or it's very convoluted how I  
23 get recognition for that. And I think there's -- from a  
24 policy standpoint, the state has some opportunities to be  
25 first in class in that area. And today I would say the

1 customers don't think so.

2 AB 32, we've heard about that. I think the ICF  
3 report had some good detailed information. You know, in  
4 the Scoping Plan, CHP, the values, was recognized and it  
5 was very clear. In cap and trade, there's a lot of  
6 uncertainty on the final rule. Is it going to really  
7 reflect CHP value? And that actually -- that uncertainty  
8 is limiting deployment right now, you're going to make a  
9 big investment, and particularly if you have a site, you  
10 know, as an example, a site that may not have CHP today  
11 and they wouldn't be in cap and trade, and they're looking  
12 at making an investment that's going to throw them into  
13 cap and trade. They may look pretty hard at that, even if  
14 the initial financials may pencil out and they say, "What  
15 am I signing up to?" So I think, 1) clarity is needed and  
16 the final rule needs to be sure that CHP is appropriately  
17 reflected on the real value it provides for greenhouse gas  
18 mitigation.

19 Departing load charges, we've heard a lot about  
20 that. I think, you know, it's clear there's action needed  
21 there. As far as we know, California is the only state  
22 that has fairly onerous charges in this regard. When you  
23 look at -- I think there was an example if you do a  
24 lighting project to be more efficient and, you know,  
25 change your lighting, etc., you don't have a departing



1 load charge; if you have CHP, you still have your  
2 departing load charge. You know, the bottom line is  
3 customer CHP on the customer side of the meter is energy  
4 efficiency and it's -- I think it's important to make sure  
5 that that's recognized and that the policies reflect that.

6 And the last one, and this one got an  
7 Incomplete. When you look at the RPS, and we've heard all  
8 the discussion this morning on the RPS, and from a  
9 positive point of view, you know, CHP provides documented  
10 benefits which complement the RPS, and when you put that  
11 on top of the fact of the leadership that, you know, in  
12 California saying, "Hey, we see the value in CHP, we want  
13 to deploy 6,500 megawatts," and then you look at the  
14 spaghetti bowl of things that have to be dealt with to try  
15 to actually deploy CHP, there's an opportunity for  
16 additional clarity to simplify this. And one -- and I'll  
17 throw this out as a bold goal -- would be for the State to  
18 consider some sort, I don't know what it would look like,  
19 and there's lots of folks that would have a lot of ideas  
20 and I'm sure good ideas, on some sort of a CHP Portfolio  
21 Standard. So if we're going to put 6,500 in, let's put in  
22 highly efficient CHP, do it in a fashion that clarifies  
23 where the State wants to go, set up the rules, and let's  
24 go. And that is, again, that's kind of a bold goal where  
25 you're asked, "Throw out -- what are the other ideas for

1 the future?" And obviously, I don't think this is a new  
2 idea, I think this has been run around various times, but  
3 when you look at the realities today and where the State  
4 wants to go with its greenhouse gas profile, this is  
5 something that ought to be in the conversation again.

6 And to conclude, if you look at needed actions  
7 to advance CHP, what the customers are telling us,  
8 eliminate departing load charges for CHP, and we  
9 particularly see it in machines our size; recognize CHP's  
10 value in cap and trade, recognize CH value to the grid;  
11 and then consider the bold goal for highly efficient CHP,  
12 to have some sort of a CHP portfolio standard to really  
13 define it and have clarity to all parties, here is where  
14 the state is going to go, go and do a good job, and deploy  
15 it. And that's what we're going to do. I thank you very  
16 much and I'd be open to questions.

17 CHAIRMAN WEISENMILLER: Thank you. Go ahead.

18 MR. TORRIBIO: Good morning. I'm Gerome  
19 Torribio with Southern California Edison and I'd just like  
20 to refer back to the report card. The grade of C for  
21 recognizing grid benefits, I wanted to ask you if you  
22 would consider appealing the grade and moving it up in  
23 light of the CHP settlement that's just become effective.

24 CHAIRMAN WEISENMILLER: Well, actually I had  
25 some specific questions for Edison on that very topic, so

1 I'm glad you stepped forward. Twenty-nine Palms, which is  
2 at the end of the line, there is a cogen project. You've  
3 had three outages at 29 Palms this month and it's  
4 adversely affecting training. What are you doing about  
5 it? And how are you incenting cogen there?

6 MR. TORRIBIO: If we've had an excessive number  
7 of outages, we certainly want to remedy that.

8 CHAIRMAN WEISENMILLER: Please do it fast.

9 MR. TORRIBIO: Yes. I think --

10 MR. ALLEN: To answer the gentleman's question,  
11 these are totally subjective direction from our customers  
12 and what we're hearing from the customer base, so I  
13 wouldn't know how to amend that grade, that's really the  
14 feeling on the street.

15 MR. TORRIBIO: Maybe you can help us with the  
16 outreach on that, then.

17 MR. ALLEN: Love to.

18 MR. TORRIBIO: Thank you.

19 MR. ALLEN: I think that's a really good point  
20 because I think the outreach and the overall, you know, I  
21 look at it and I look at this as the CHP community and I  
22 think the CHP community needs to continue to really look  
23 at how do we -- we get to focus on the goal and figure  
24 out, well, how do we get the policies in place to really  
25 deliver it and create a market system that works? You

1 know, I keep hearing -- I've had it explained to me that,  
2 you know, CHP, if we're in a horse race, if that's the  
3 market, we've got a fast horse, but we've got a 100 lb.  
4 saddle, and we're asking our customers to say, "Give us  
5 the two pound saddle that the other horses are running  
6 with and let's see how it goes." And that's really, I  
7 think, what the whole CHP industry and community really  
8 needs to start to continue to focus on with the end in  
9 mind, is get to the finish line and deliver results that  
10 are really meeting the energy goals, in this case, the  
11 State of California.

12 MR. TORRIBIO: Thank you.

13 MR. TUTT: Good morning, Tim Tutt from SMUD and  
14 I just wanted to make a brief comment about the RPS  
15 Portfolio Standard vs. a CHP Portfolio Standard. As  
16 utilities in the state, we all procure energy, some  
17 imported, some in our service areas. So we all kind of  
18 face a level playing field of an RPS Portfolio Standard  
19 with the same options and, in general, where a CHP  
20 situation, we're looking at CHP potential within our  
21 service areas, and that varies significantly. So the same  
22 kind of structure doesn't fit quite as well to CHP in our  
23 opinion, as the RPS does for renewables. Thank you.

24 MR. NEFF: Thank you, Joe. I think the panel  
25 has tried to address most of these questions. Before I

1 get started, I'm going to turn to the dais and see if  
2 anybody has any additional questions they would like to  
3 ask the panel as a whole.

4 MR. RECHTSCHAFFEN: I just want to know what my  
5 grade is and what Bob's grade is. We're on an incentive-  
6 based system here -- no, I thought it was very helpful.

7 CHAIRMAN WEISENMILLER: Yes, no, I think it's  
8 good.

9 MR. NEFF: All right. I have a couple  
10 additional questions. I think we did a pretty good job of  
11 talking about the first question and that the investors  
12 are really responding to the price signals that are there  
13 and the playing field that's been set out. I'd like to  
14 ask more specifically on the second bullet, what is the  
15 single-most difficult task you've had at installing your  
16 project, or, for the manufacturers, what is the single  
17 largest reason for project failure?

18 MR. RUARK: From Sonoma County's perspective,  
19 the delay in the project, the biggest delay was  
20 interconnection, getting interconnection agreement to be  
21 signed. And at this point, it's just getting the feed in  
22 tariff for the excess electricity put on the grid.

23 MR. ALLEN: Yeah, from Solar Turbine's  
24 perspective, that's what we seem to hear, too, is that  
25 interconnect is challenging just in how convoluted and the

1 length of time and cost to do it.

2 MR. HAKE: I think I have already maybe talked  
3 enough about our interconnection issues, but in terms of  
4 the REC value, I would go back to that as being, you know,  
5 maybe a primary component in our decision to move forward  
6 with a project financially since we were self-financed.

7 MR. MARTINI: Since everyone else picked two  
8 things, I'm going to pick my two, would be the departing  
9 load charges and the lack of net energy metering for small  
10 CHP, I think that's been our biggest shortfall.

11 MR. NEFF: All right, moving to the third  
12 bullet, what can the State do to focus in on either a  
13 regulation that is existing and negatively affecting the  
14 CHP market, or a possible future regulation that will have  
15 a positive effect on the CHP market?

16 MR. RUARK: I love John's idea about a tiered  
17 structure for feed in tariffs based upon renewables. We  
18 have a fuel cell we could be using biogas in, however that  
19 cost, we don't have that capacity to pay the extra cost.  
20 But if the tiered structure was available, we might be  
21 able to buy biogas and make it economically viable.

22 MR. HAKE: Biogas requires quite a bit of  
23 conditioning, especially if it's going to be used in a  
24 fuel cell, so there would be a lot of additional cost for  
25 that, so that's definitely a factor.

1           MR. ALLEN: I think one of the more near term  
2 actions that could be taken is, you know, SGIP because  
3 that program is a successful program and the fact that  
4 these technologies are back in is to provide a little more  
5 certainty on the length and consider extending that  
6 program out beyond the 2016 and, you know, continue to  
7 look at leveling it a little bit from an incentive  
8 standpoint so that there's a little more balance in the  
9 incentives that are going to be provided, if they're  
10 leveled a little bit more between the technologies.

11           MR. NEFF: Is there anybody from the audience  
12 that has questions? Anybody online? No questions online.  
13 Well, thank you panelists. Thank you for your  
14 contribution and I'll be moving on to some Industrial CHP  
15 issues. We have two presenters left before lunch, so  
16 we're going to try and get to those right away.

17           The next presenter is Dr. Barbara Barkovich.  
18 She is was a consultant and expert witness on energy and  
19 regulatory matters, including marginal costs, cost  
20 allocation, and rate design, electric industry  
21 restructuring, and electric resources analysis. Dr.  
22 Barkovich is Chairperson on the Board of Restructuring  
23 California Power Exchange. She has also served on the  
24 California Independent System Operator Governing Board and  
25 the Energy Engineering Board of the National Research

1 Council. She has previously worked for the CPUC, ending  
2 up as director of Policy and Planning.

3 DR. BARKOVICH: Well, I'm going to try to be  
4 brief to not get in between you and your lunch. And  
5 actually a number of things that I'm going to talk about  
6 have been mentioned before, but I'm going to attempt to  
7 bring a perspective of customers who have the potential  
8 for bottoming cycle CHP, which is the kind of CHP that  
9 almost always gets forgotten, and also customers who are  
10 maybe bigger than the small CHP, but smaller than the big  
11 CHP, sort of Mama Bear sized CHP, and also customers whose  
12 focus is onsite usage for which things like 1613, etc.,  
13 don't really make much difference.

14 So bottoming cycle CHP basically, for those of  
15 you who don't know what it is, you basically have an  
16 industrial process that has fuel that comes in and is a  
17 high temperature process. And at the end of that process,  
18 you've done whatever you've done, made clinker in a cement  
19 plant, melted glass or something, and you've got waste  
20 heat. You can do a number of those things with waste  
21 heat. But one of the things you can do with it, or part  
22 of it, is to make electricity. You can make electricity  
23 using that waste heat without any supplemental addition of  
24 heat, in which case it's basically pure bottoming cycle  
25 CHP and has the equivalent of an infinite efficiency.



1 That is, electricity with no fuel input because the fuel  
2 has already gone into the industrial process and would  
3 have gone in there regardless of whether you made  
4 electricity or not. And this is something that was  
5 recognized by the Energy Commission in its AB 1613  
6 Regulations for defining the Electrical Efficiency  
7 Standard for Bottoming Cycle vs. Topping Cycle CHP.  
8 That is a distinct attribute of bottoming cycle CHP.

9           The other thing about bottoming cycle CHP is it  
10 is very industry and facility specific, and this relates  
11 to the nature of the process that creates the waste heat,  
12 if it's an existing facility it has to do with the  
13 configuration, the space available to put the waste heat  
14 recovery system in, etc.

15           So the experience, at least of my members, has  
16 been that when you get an indicative bid, it looks like it  
17 could be a really good fit for you, and by the time that  
18 they give you the full bid package, it costs three times  
19 as much and doesn't make any sense anymore.

20           So to finish my summarizing of bottoming cycle  
21 CHP, it doesn't tend to -- I mentioned onsite usage -- one  
22 of the reasons for onsite usage is that, for an average  
23 industrial facility, the part of the process that produces  
24 the waste heat is only a fraction of the total industrial  
25 process, therefore the electricity that you could make

1 using the waste heat tends to be less than your entire  
2 load. So it's not an issue of producing so much you want  
3 to export it because you have an excess of your needs, and  
4 the economics are such, as well as the hassle factor is  
5 such, that using it onsite in many ways makes more sense  
6 than trying to export everything and buy your power from  
7 the grid or from, you know, through some other supplier.

8           The other thing is that there really are very  
9 few incentives available as has been pointed out. The  
10 SGIP incentives, which now are available once again for  
11 CHP, also include a line item which is called Rankine  
12 Cycle, which we believe was the PUC's attempt to refer to  
13 bottoming cycle, even though that's not the only potential  
14 bottoming cycle technology, but you have a set of  
15 incentives that you get the full incentive for the first  
16 megawatt, half the incentive for the next megawatt, and  
17 half the incentive for the next megawatt. Well, if you're  
18 a three megawatt project, that might look pretty good, but  
19 given that the size of a project is going to be totally a  
20 function of the amount of waste heat and the source of the  
21 waste heat at the customer premises, at least for a cement  
22 plant, a bottoming cycle project might be eight to 10  
23 megawatts, so you really are only getting a declining  
24 incentive on the first three megawatts, and this is part  
25 of what I believe is a longstanding bias in California

1 against things that are bigger than large bread boxes, so  
2 that, as we know, things under five megawatts are always  
3 better than things above five megawatts, and in the case  
4 of the SGIP, things under three megawatts are obviously  
5 better than things bigger than three megawatts. And the  
6 reasoning always is, "Well, we only have so much money and  
7 we have to spread it around." But the reality of the  
8 situation is that there are lost opportunities because  
9 larger customers can never get equivalent benefits to  
10 smaller customers -- the issue of economies of scale,  
11 notwithstanding.

12 All right, I'm supposed to be doing slides,  
13 right? Okay, sorry about that. I'm caught up now.  
14 Tradeoffs with energy efficiency in terms of the heat  
15 available, several speakers have made the point that CHP  
16 is energy efficiency. In the case of bottoming cycle CHP,  
17 as I said, what happens? You put the fuel into the  
18 industrial process, you do whatever you're going to do in  
19 the industrial process, and you get the waste heat out.  
20 Then you have choices about what to do with the waste  
21 heat. The preference has been policy-wise to do all cost-  
22 effective energy efficiency first, and traditionally  
23 that's what industrial consumers do. For example, in a  
24 cement plant, you will take that waste heat and you will  
25 use it to preheat the input to the kiln, you don't waste

1 the energy. But the more energy efficiency you do, the  
2 lower the grade of the heat is to make the electricity.  
3 And so, if you "exhaust all cost-effective energy  
4 efficiency first," depending on how you define cost-  
5 effective, you can be in a situation where the quality of  
6 the waste heat that's left doesn't produce very much  
7 electricity. And because of the policy of doing all cost-  
8 effective EE first, there's no co-optimization with  
9 electricity production. I mean, that has just simply not  
10 historically been considered. And for a while, when there  
11 was no SGIP funding available for CHP, maybe it didn't  
12 matter so much. And certainly the Energy Commission  
13 Standards for AB 1613 specifically discuss doing energy  
14 efficiency first. But there does need to be an  
15 understanding that there's a tradeoff there.

16 And then, as I said before, and this has been  
17 said as well, bottoming cycle CHP without supplemental  
18 firing is effectively energy efficiency; you're taking  
19 waste heat, you're turning it into electricity. And as I  
20 mentioned before, a lot of these projects with respect to  
21 industrial facilities are going to be in the three to 20  
22 megawatt range. So they're going to be less than 20  
23 megawatts, but they're going to be bigger than the small  
24 cogen you've been listening to discussion about.

25 Supplemental Firing. One of the things you can

1 do is to add some additional heat into the process before  
2 you convert the waste heat to electricity. And that's  
3 called Supplemental Firing. It does involve some GHG  
4 because supplemental firing is normally done with  
5 something like natural gas, but it can significantly  
6 increase the output. And one of the things that we  
7 demonstrated as part of the Energy Commission's rules for  
8 AB 1613 is that there are -- you can have a significant  
9 level of supplemental firing and still, on an electrical  
10 efficiency basis, an emission basis, be better than a new  
11 combined cycle power plant, which is the reason why the  
12 electrical efficiency requirement for bottoming vs.  
13 topping cycle under AB 1613 is different -- has to do with  
14 going through all the chemical engineering calculations.  
15 But the analysis can be done and has been done by your  
16 staff.

17           This point has been made and I'm delighted it's  
18 been made so I can make it relatively briefly. Without  
19 supplemental firing, bottoming cycle CHP is pure energy  
20 efficiency. But, if you do something to your facility --  
21 improve your lighting, putting variable speed drives,  
22 whatever, improve your efficiency, reduce your usage, you  
23 don't get departing load charges. You put in bottoming  
24 cycle CHP in and you get departing load charges. It  
25 doesn't seem quite equivalent.

1           Customers using CHP do not have to pay the CTC,  
2   the Competition Transition Charge, which is amazingly  
3   still around since 1995, even though the reason for it  
4   might have gone away, but that, at least for that 3,000  
5   megawatts, but they do have to pay for the PGC, what was  
6   the PGC, that's the low income program, it's the energy  
7   efficiency program, what is now called the EPIC, and DWR  
8   Bond charges, and this slide forgot nuclear  
9   decommissioning because I put this together in about three  
10   seconds. Again, those charges would not apply if you had  
11   a load reduction due to EE.

12           Cap and Trade. We've heard some discussion  
13   about this, as well, that's the advantage of Mr. Silva and  
14   me battling clean-up. The utilities receive free  
15   allowances from CARB, are going to based on historical  
16   load. That historical load includes the load of customers  
17   who currently do not have CHP, but might choose to install  
18   CHP in the future, so that if those customers had not  
19   existed, that utility share of the free allowances would  
20   be smaller. If that customer doesn't have CHP and adds  
21   CHP, and the utility does not allow some of that CHP value  
22   to go to the customer adding CHP -- I'm sorry, cap and  
23   trade value to go to the customer adding CHP -- then the  
24   utility ends up with more allowances and less load. The  
25   customer who departs, on the other hand, now if it has

1 onsite CHP and does have -- let's say there's supplemental  
2 firing for bottoming cycle where it's a topping cycle  
3 situation, they now have an additional cap and trade  
4 obligation for GHG associated with their onsite generation  
5 that didn't exist before. If they're EITE, it's not in  
6 their baseline because they didn't have it when the  
7 baseline was calculated, so the utility and the remaining  
8 utility customers basically get relatively more and that  
9 customer gets a relative disincentive because, if it  
10 stayed with the utility, it would be able to keep that  
11 share of the allowance value, whatever share the Public  
12 Utilities Commission ends up deciding to give it. So,  
13 there seems to be an equity issue here if you're trying to  
14 create an incentive for new CHP for existing customers.  
15 Probably enough said. And that's it.

16 CHAIRMAN WEISENMILLER: Thanks, Barbara. I was  
17 going to circle back on the cap and trade issue and ask if  
18 you have specific proposals on how the utilities could  
19 share that credit with potential CHP project.

20 DR. BARKOVICH: Indeed, we do. We actually  
21 submitted comments at the Public Utilities Commission on  
22 this point and made the argument that if an existing  
23 utility customer, agreed customer, were to subsequently  
24 engage in onsite CHP that they would have allowance  
25 portability. That is that they would be able to take

1   either -- if the allowance were monetized, they would be  
2   able to get some credit on their bill that would be the  
3   equivalent of what they would have gotten if they'd stayed  
4   as a bundled customer, and if they were actually -- if the  
5   Commission -- if CARB changed the rules that the  
6   Commission could actually give customers allowances, as  
7   opposed to giving customers allowance value -- monetized  
8   allowance value -- that the customer could take  
9   allowances. And we believed, and this -- we could send  
10  them to you, I mean, this is all in the PUC record, but we  
11  believe that this would not disadvantage the remaining  
12  customers because those original allowances were  
13  predicated on that load continuing to be with the utility.

14           MR. RECHTSCHAFFEN: So when you say the  
15  equivalent share that the utilities would have received,  
16  you're sort of doing a pro rata share of the allowances  
17  they get based on the load that was on the system before  
18  the CHP System was installed?

19           DR. BARKOVICH: Right, and Ray is undoubtedly  
20  going to tell you why this can't be done, but that is our  
21  recommendation at the PUC.

22           CHAIRMAN WEISENMILLER: Okay, could you also  
23  submit that in our docket?

24           DR. BARKOVICH: Oh, sure.

25           CHAIR WEISENMILLER: Thanks. Ray.



1           MR. WILLIAMS: I just wanted to address this  
2 issue. The way that the allowance allocation was set for  
3 the utilities was based partially on load, partially on  
4 historic emissions, and partially recognition as to how  
5 well various utilities did in terms of energy efficiency  
6 in RPS in terms of promoting clean generation. And then  
7 it's fixed and the reason that it's fixed is, over time,  
8 you didn't want a utility to get more allowances, by  
9 increased emissions to get more allowances, it's a bad  
10 signal. So that's the way it was set initially. Now,  
11 moving to the PUC, all utilities pledged that the revenues  
12 that we received through the auctions, which is what the  
13 IOUs have to do, or the allowances directly, which is what  
14 the PUCs have available to them, go back to customers.  
15 None of them go back to utility shareholders, so we need  
16 to be really clear about that.

17           So then this becomes an allocation issue for the  
18 benefit of utility customers, okay? And what Barbara is  
19 talking about is a situation where load goes down because  
20 CHP is installed. You know, for a particular customer,  
21 their allocation will depend on essentially the amount of  
22 electricity they buy from the utility. So, I mean, the  
23 converse to that, you could say if you're looking at an  
24 individual customer, is if a customer no longer has a CHP  
25 because they lose their steam host, they will receive more

1 allowances presumably because they will be buying more  
2 electricity from the utility, so there's two sides to  
3 that.

4           Now, I'm going to go to a place where I don't  
5 know much, but I think it's worth investigating. And that  
6 is, as part of the industrial sector allocation, it's  
7 based on energy intensive, trade exposed criteria and it's  
8 sort of benchmarked, and I believe the amount is actually  
9 updated from time to time because you really have to track  
10 the individual industrial customers' circumstances. That  
11 is a place in that updating that circumstances change with  
12 respect to CHP, whether they're installing more CHP, or  
13 less. It's another place to go to try to make a CHP  
14 customer (inaudible). I understand that it does, you  
15 know, that they will have a compliance obligation if  
16 they're above a certain threshold and that's maybe a place  
17 to address that, as those circumstances change. But I'm  
18 really at the end of my knowledge in terms of how the  
19 industrial sector allocation works.

20           DR. BARKOVICH: I think it's possible you're  
21 beyond your knowledge in terms of the updating, but we may  
22 be able to clarify that. I know Evie calls here and she  
23 knows those Regs even better than I do, and I've spent  
24 more time on this than I want to, but I'm not -- I mean,  
25 my understanding is that, for EIT -- first of all, we've

1 got both EITE and non-EITE customers who can do CHP. For  
2 EITE customers, their allowances are based on historical  
3 baseline. And for non-EITE customers, yes, they weren't  
4 given any allowances by CARB because they weren't EITE,  
5 and if they install CHP and leave the utility, they're  
6 going to lose the reimbursement from the free allowances  
7 that they would have gotten if they'd stayed with the  
8 utility. So I still think it's a valid point.

9 MS. KAHL: And I agree with Barbara, right, that  
10 when a customer -- the only way you can get an increase in  
11 your greenhouse gas allocation from CARB if you're EITE is  
12 if your output changes. And so a shift in your  
13 electricity source doesn't generate more greenhouse gas  
14 allowances for you, so that's not --

15 DR. BARKOVICH: Mic, mic.

16 MS. KAHL: I'm sorry, I'm Evelyn Kahl.

17 MR. RECHTSCHAFFEN: And then there's the whole  
18 sector that doesn't get allowances at all because they're  
19 too small and they're not directly regulated under AB 32.  
20 The panel we had before that these issues are raised in a  
21 very salient way with, as well.

22 DR. BARKOVICH: Right, this would definitely  
23 apply to them because they don't get any allowances,  
24 period. And as somebody said, in order -- putting in CHP  
25 would put them over the 25,000 mark and require them to be

1 subject to cap and trade, they might think twice about it  
2 -- I believe somebody said that -- because it does add a  
3 level of complexity to your life.

4 CHAIRMAN WEISENMILLER: Okay. Thanks, Barbara.

5 MR. NEFF: Thank you, Barbara.

6 CHAIRMAN WEISENMILLER: Good to see you again.

7 DR. BARKOVICH: We went to school together.

8 CHAIRMAN WEISENMILLER: We did.

9 MR. NEFF: Next up is Tom Silva. Tom Silva is  
10 the Power Policy Manager for California within the power  
11 advocacy and commercial solutions group for Chevron's  
12 Global Power Company. Mr. Silva provides regulatory and  
13 power advocacy support for Chevron's upstream and  
14 downstream California assets, specializing in power, gas,  
15 and electric utility and state regulatory issues. Prior  
16 to joining Chevron as a consultant, Mr. Silva enjoyed a  
17 28-year career with Pacific Gas & Electric, most recently  
18 serving as Senior Corporate Account Executive in Corporate  
19 Services and Sales as lead for PG&E's Oil and Gas Industry  
20 Business Segment.

21 MR. SILVA: Thank you very much. I'm thankful  
22 for the opportunity to present Chevron's view on CHP and  
23 to provide a perspective on the industrial application of  
24 CHP and illustrate how Chevron has embraced CHP  
25 technology.

1           As we are all aware, current California  
2   legislation strongly supports energy efficiency and  
3   greenhouse gas emission reductions, and CHP is a critical  
4   component of California's Climate Change Initiative. Yet,  
5   when industry seeks to employ energy efficiency measures  
6   with a byproduct of power, it is faced with a number of  
7   barriers to implementation.

8           I'd like to give you a little perspective on  
9   Chevron and CHP. Chevron embraces energy efficiency.  
10   Every manager is empowered to engage energy efficiency  
11   wherever possible. And we have been employing CHP  
12   technology in California operations for over 25 years. We  
13   have a long history of utilizing CHP in industrial  
14   applications with over 50 units representing 1,140  
15   megawatts embedded in California refineries, oil and gas  
16   operations, and in our joint venture power facilities that  
17   supply power to our energy intensive operations and it  
18   eases the load on the power grid. Chevron is one of the  
19   larger power consumers in the State of California, as well  
20   as one of the largest industrial users of CHP power  
21   generation.

22           In our San Joaquin Valley operation, Chevron  
23   engages in enhanced oil recovery activities and we extract  
24   oil products during those operations. Due to location and  
25   existing utility resources, Chevron has installed our own

1 electric distribution grids and one of the main purposes  
2 for this is to ensure reliability. We utilize boilers in  
3 CHP generation to power our equipment and to facilitate  
4 the extraction process.

5           Chevron is typically interconnected to the  
6 electric utility grid through transmission substations.  
7 These substations often serve as the point of common  
8 coupling to the CAISO controlled grid. Now, at Cymric, we  
9 have the opportunity to employ energy efficiency and to  
10 test the new technology, the bottoming cycle CHP that  
11 mines waste heat that we inject and then recover through a  
12 proprietary process. Cymric is a one megawatt bottoming  
13 cycle CHP technology pilot that produces the following  
14 benefits: energy efficiency, waste heat recovery, high  
15 reliability, energy production without additional  
16 combustion, and we reduce greenhouse gas emissions,  
17 thereby reducing greenhouse gas emissions. Our project  
18 aligns favorably with California standards for efficiency  
19 in emissions. This is a new technology that is viable.  
20 If piloted successfully, we can deploy this technology  
21 across our oil fields and at our refineries.

22           At this point, the technology has not been  
23 implemented because of the barriers we have faced and the  
24 challenges of small non-merchant CHP application sees in  
25 the marketplace. While Chevron had initial plans to

1 install 50 MW within California, we have now been forced  
2 to reduce our roll-out to less than half of what we had  
3 originally planned, and all of this is a result of the  
4 experiences we've had from this pilot project.

5           What you see now is a simplified timeline that  
6 addresses the parallel paths of AB 1613 legislation and  
7 Chevron's experience with its Cymric pilot project. As  
8 you can see by the timeline, AB 1613 legislation was  
9 enacted in 2007, but final approved contracts were not  
10 made available to CHP customers until the very end of  
11 December in 2011. The delay in outcome and implementation  
12 created a great amount of uncertainty and created  
13 additional expense to Chevron.

14           A key point here is that we were required to go  
15 through two different Rule 21 application processes with  
16 PG&E. Our engineers had originally endeavored to install  
17 a three megawatt pilot project behind an existing point of  
18 common coupling, behind CHP that we had in the field. We  
19 were told by PG&E that we could not install the unit at  
20 that location, and so therefore we had to redesign the  
21 project on a smaller scale and reapply for a new Rule 21  
22 application. And now, at the end, as you can see down in  
23 December -- or in October of 2011, Chevron was told by  
24 PG&E that we would now have to file the PG&E Wholesale  
25 Distribution Access Tariff and that would put us into the

1 more costly CAISO Independent Study process and it would  
2 require additional expense.

3 From mid-2008 when Chevron first brought the  
4 project to PG&E, through late 2011, we have suffered  
5 critical time delays that have threatened the very  
6 implementation of this project. Although a more  
7 streamlined process is available, we have come to  
8 understand that there have been no Greenfield fast track  
9 applications cleared by PG&E.

10 We're all aware that California is the leader in  
11 energy efficiency in the United States, yet if you place a  
12 turbine behind a pure energy efficiency project, you face  
13 significant burdens. And those delays lead to a lost  
14 benefit in greenhouse gas emission reductions, energy  
15 efficiency, and increased cost to developers of the  
16 projects. CHP is an important capital investment for  
17 Chevron, but the entire process often makes it untenable.

18 We understand that Regulations are enacted to  
19 promote the development of efficient CHP, yet the delay in  
20 AB 1613's implementation created a great amount of  
21 uncertainty for small CHP development in California.  
22 Instead of supporting CHP, in practice the process has  
23 gotten in the way. For example, over the last two years,  
24 I believe there were almost 10 different filings by the  
25 utilities questioning the validity of AB 1613 legislation,



1 and these including petitions, advice filings, and  
2 requests for re-hearings; all of these impacted our  
3 project.

4           So what are the three challenges that we've seen  
5 at our Cymric project? First, there's the threat to  
6 existing CHP, and some of you have addressed this. I have  
7 to admit, we have a really good contract at Cymric right  
8 now, a very good Power Purchase Agreement. We have  
9 existing CHP in our oil field there. Yet, if we installed  
10 our project behind the point of common coupling, we were  
11 told by PG&E that they would cancel the Evergreen  
12 Contract. And so, as a result, it forced us to reevaluate  
13 our project. We had to reconnect at a new point of common  
14 coupling, we had to rescale the project and relocate the  
15 site. We have to install new distribution level  
16 interconnection facilities. And now, as a result of all  
17 of this, we will now have power sales onto the grid  
18 because we were told by PG&E that we could not utilize the  
19 power produced in this pilot project at the site. As a  
20 result of that, we are now engaging in an AB 1613 Power  
21 Purchase Agreement for those sales onto the grid. But it  
22 doesn't stop there. We are no longer eligible for the  
23 self-gen incentive program for this waste heat recovery  
24 project because, with no host for our generation, we  
25 become ineligible under the SGIP requirements because we

1 are now selling more than 20 percent of our power onto the  
2 grid.

3           So the second barrier we encountered was the  
4 interconnection process, itself. PG&E was very helpful in  
5 offering us alternative sites for interconnection, but  
6 that required reengineering from our Chevron resources,  
7 both for the project and the time delays in getting this  
8 done. Now we're required to have a new System Impact  
9 Study for the new point of common coupling.

10           As we move from the Rule 21 application process  
11 into the PG&E wholesale distribution access tariff  
12 process, which is, by the way, much more complex, it is  
13 much more costly. The Rule 21 application was \$800.00.  
14 The WDT process requires a \$50,000 deposit. Now, if we  
15 had rolled out the original project with 40 different  
16 installations that we've identified, that would be a  
17 considerable expense for Chevron.

18           We are also engaged in the lengthy CAISO  
19 Independent Study process and all of this for a one  
20 megawatt distribution level interconnection? And then,  
21 finally, our point -- our bottoming cycle project is not a  
22 wholesale generator, and I think we've heard everyone else  
23 talk about that today, but yet our one megawatt pilot is  
24 basically viewed in the same way that a wholesale  
25 generator would be with regard to the interconnection

1 process. And instead of being seen, as Barbara stated, as  
2 a pure energy efficiency measure, we're really viewed as a  
3 wholesale generator in the process. We had no desire to  
4 sell power when we engaged in this project in the first  
5 place.

6 We believe there should be a differentiation in  
7 the regulatory treatment for industrial processes and  
8 applications that deliver small amounts of as available  
9 power onto the grid vs. true merchant generator  
10 applications. We are not wholesale generators and we  
11 believe projects like ours should be treated differently.

12 In addition, the attempt to impose resource  
13 adequacy or full capacity deliverability status should  
14 never apply to these types of projects. They are not  
15 curtailable. And if it had been approved, it would have  
16 made our project impossible to implement. This is a very  
17 small project, it has been subjected to a number of  
18 delays, applicable more to a transmission level merchant  
19 generator than this internal industrial process  
20 application should have required.

21 So what can we do to encourage CHP in  
22 California? We believe that the current regulatory  
23 environment has created uncertainty in the market. As I  
24 exhibited on the timeline earlier, implementation or  
25 timely implementation is critical. When we conducted our

1 analysis at Chevron, we first initiated this project, I  
2 believe, in 2008 in our internal discussions, and a good  
3 question was how would we be governed at the end of the  
4 day. Chevron would also like to see a clear path forward  
5 for implementing new technologies like this on a much  
6 broader scale.

7 And I do want to mention that the utility  
8 partners and the regulatory agencies were very helpful in  
9 ushering us through the process, but essentially they  
10 threw up their arms and said, "You know, I know this  
11 doesn't make a lot of sense, but it is the process we're  
12 forced to live under, and therefore this the way we have  
13 to go." So we would like to see a much more streamlined  
14 process in the future.

15 And I don't think anyone has mentioned it today,  
16 but small CHP is still faced with the generation behind  
17 the generation problem, this is behind the point of common  
18 coupling. We have identified a number of opportunities  
19 for application of this type of technology, a location  
20 served by existing CHP and existing Power Purchase  
21 Agreements. In order to preserve the PPAs, do we really  
22 have to interconnect at a different point of common  
23 coupling, all when the power is consumed onsite? So, for  
24 many of our applications, CHP is used as an energy  
25 efficiency measure. Power generation is simply a

1 byproduct of the process. We typically size our CHP and  
2 our industrial applications to meet our steam needs, so  
3 there may always be a potential or some excess power onto  
4 the grid. Actually, in a perfect world Chevron would like  
5 to be able to use power generated on one site and flow it  
6 to another, but I know that will be a challenge.

7           As has been stated before, Chevron also  
8 disagrees with the current application of departing load  
9 charges. They should at least have a date certain end.  
10 We question the applicability of these charges for this  
11 type of project. We wonder if the utility is ever  
12 considered, the load we generate behind the point of  
13 common coupling, in their long range plans.

14           So in closing, because of our experiences within  
15 the current environment and the time consuming  
16 interconnection process, Chevron has scaled back its  
17 efforts to install new CHP in California. We will no  
18 longer consider sites governed by existing PPAs and will  
19 only consider employing energy efficiency and greenhouse  
20 gas mitigation technology at Greenfield installations in  
21 the future, that is, unless regulations change. So thank  
22 you very much.

23           CHAIRMAN WEISENMILLER: Thank you. Actually, I  
24 was going to point out that, when I worked with Chevron on  
25 the Richmond Cogen Project, it turned out there was a

1 cogen facility there since the '30s that was shut down  
2 eventually when the current project came online. So your  
3 history is even a little further than you think.

4 MR. SILVA: Okay, thank you.

5 CHAIRMAN WEISENMILLER: Thank you. A couple  
6 questions. I guess one, for the PUC, in terms of -- is  
7 the definition of Rankine -- was that the intent to cover  
8 bottoming cycle? Or do we need some clarification there?  
9 Or do you need more time to think about that?

10 MS. KALAFUT: I would have to check with our  
11 SGIP Program staff about the intent behind the organic  
12 Rankine cycle definition in the rule, but my guess would  
13 be that the intent was for bottoming cycle, not just  
14 Rankine cycle.

15 CHAIRMAN WEISENMILLER: Yeah, that would be my  
16 guess. If you could clarify that for the record, that  
17 would be great.

18 MS. KALAFUT: Okay.

19 CHAIRMAN WEISENMILLER: So, in terms of the  
20 sorry saga at Chevron, I guess, Dennis, is there a way  
21 from the ISO to get them out of the WDAT process? I'd ask  
22 the same question, obviously, to Ray.

23 MR. PETERS: Good afternoon. Dennis Peters with  
24 the California ISO. Well, I really can't comment on --

25 CHAIRMAN WEISENMILLER: The specifics, I know.

1           MR. PETERS:  -- well, specifically on why they  
2   were required to go underneath PG&E's wholesale  
3   distribution tariff.  With regard to how the ISO's  
4   involved in that, WDT, or WDAT projects for the other two  
5   utilities, they do find their way into our base cases for  
6   our generator interconnection process.  So I wouldn't be  
7   able to comment on why it was moved from Rule 21 to the  
8   WDT, I guess PG&E would have to comment on that.

9           CHAIRMAN WEISENMILLER:  Yeah.  But, I mean, my  
10  presumption is that, if there is anything the ISO can do  
11  to help move along bottoming cycle within your tariffs,  
12  you should try to do that.

13          MR. PETERS:  Yeah.

14          CHAIRMAN WEISENMILLER:  Ray, again, I don't know  
15  if you really have the background on this specific -- if  
16  you guys want to comment on that later, but this is not a  
17  happy story.

18          MR. WILLIAMS:  Yeah, I don't spend a lot of time  
19  on interconnection.  The one thing I was going to point  
20  out later is that, as part of the QF CHP Program, we do  
21  recognize that generators have a lot of obligations; they  
22  come in part from the QF CHP Settlement and they come in  
23  part from signing a contract of some sort which puts them  
24  into an interconnection process of some sort.  We did try  
25  to sort out, based on your situation, where it was that

1   you needed to go, and we presented that to the QS, but  
2   it's not the -- we tried to make it as clear as we could  
3   it's not simple and clearly -- you know, we're working on  
4   Rule 21, the settlement discussions as was determined --  
5   talked about early, so that's at least one element of  
6   moving the interconnection process along more smoothly.

7               CHAIRMAN WEISENMILLER: Yeah, it seemed like  
8   this one is certainly -- if you could sit down with  
9   Chevron and try to work through some of these things and  
10  get back to us, again, it's sort of -- as we know, the  
11  interconnection processes are complicated, but having to  
12  go from one to the other just seems like, you know,  
13  incredible difficulties being presented, or being put in  
14  the way of getting these projects done.

15              MR. WILLIAMS: I'll talk with Tom and find the  
16  right people, and I think it's on the Electric  
17  Transmission side, and see if I can get them connected.

18              CHAIRMAN WEISENMILLER: Okay, great. Thanks.

19              MR. SILVA: Well, for the record, the project is  
20  moving forward and PG&E has been ushering us. I think  
21  what we were dealing with was the front end process there,  
22  you know, would like to see a way where we could install  
23  this technology and not violate existing contracts. You  
24  know, we're looking at reliability of our operations and  
25  energy efficiency and we think that something as simple as



1 check meters or agreements with -- or amendments to the  
2 existing Evergreen Agreement would be sufficient in many  
3 cases, but to force us through the process we went through  
4 is pretty cumbersome.

5 CHAIRMAN WEISENMILLER: Well, again, I think  
6 certainly for the Commission's and for PG&E and Edison,  
7 energy efficiency is at the top of the loading order, so  
8 trying to figure out ways to achieve these benefits, you  
9 know, it would make sense for everyone to work together on  
10 it. Okay, any other questions for either Dr. Barkovich --  
11 sure.

12 MR. BROWN: Good morning, it's Andy Brown from  
13 Ellison, Schneider and Harris. I've been asked to come  
14 down on behalf of Praxair Plane Field. They're an  
15 industrial gas producer. The process there is very energy  
16 intensive. And they have a situation where I think it's  
17 touching on some of the stuff that Dr. Barkovich addressed  
18 with respect to the impacts of the CARB GHG Program.  
19 Specifically, they have a production site that's in  
20 Southern California on the border of LADWP and Edison, and  
21 they are, in light of some upcoming retail rate increases,  
22 looking at restarting an existing CHP that they have that  
23 has been turned off because they were able for a period of  
24 time to have some rates that made it beneficial not to  
25 operate the cogen. The problem that they're seeing is the

1 one where, if they operate the cogen, they'll now carry a  
2 GHG compliance cost which doesn't obviously exist on them  
3 as a grid connect customer. But at the same time, they're  
4 not going to get a flow back of any of the auction  
5 revenues if they are no longer taking from the grid. So  
6 the grid connected customer has an offset if you do go to  
7 operate a cogen, as mostly just to serve your own load,  
8 you actually are facing a disincentive because you don't  
9 have any of those offsetting revenues.

10           Additionally, because the project is on that  
11 border, there isn't a parity of the rules at CARB between  
12 the handling of GHG allocation offsets by POUs vs. IOUs,  
13 and so that also creates a bit of a conundrum there. And  
14 so this is, in essence, a barrier issue in terms of an  
15 application of cogen at an industrial site that, you know,  
16 probably could make sense in light of the rate increases  
17 that are anticipated to come in large part because of RPS,  
18 among other things.

19           CHAIRMAN WEISENMILLER: That's good. Certainly,  
20 again, if you have specific suggestions on how to move  
21 forward, it would be great if you could submit those to  
22 the record.

23           MR. BROWN: Yeah, I think we're going to be  
24 looking at presenting those in the written comments.

25           CHAIRMAN WEISENMILLER: That would be good.

1 MR. BROWN: Thank you.

2 MR. NEFF: Do you have any more questions?

3 CHAIRMAN WEISENMILLER: No.

4 MR. NEFF: All right, well I think we've reached  
5 our lunch break. Thank you, Barbara and Tom, for  
6 presenting. We'll be returning in an hour --

7 CHAIRMAN WEISENMILLER: Actually at 1:30.

8 MR. NEFF: So 1:30, just shy of an hour from  
9 lunch to conclude the rest of our day's events. So thank  
10 you, all presenters who presented this morning, and we'll  
11 see you after lunch.

12 (Recess at 12:35 p.m.)

13 (Reconvene at 1:37 p.m.)

14 MS. KOROSSEC: All right, if you'll take your  
15 seats, we'll go ahead and get started again. I'll pinch  
16 hit for Bryan here, I think he's taking care of some last  
17 minute business.

18 We'll start back with the topic of Innovative  
19 Financing for CHP Development and our first speaker is Tom  
20 Casten from Recycle Energy Development, who is a member of  
21 ACORE.

22 MR. CASTEN: Thank you very much for the -- can  
23 you hear me? Am I good? Thanks for the opportunity. I'm  
24 going to very quickly review what I think is good to  
25 encourage CHP, talk about some problem areas, explain some

1 added values very quickly that I think justify more time,  
2 and then make some suggestions. But in order to do that,  
3 I thought I needed to tell you about my dog. I got this  
4 wonderful Australian Sheppard, one-year-old, his name is  
5 Guido, he's intelligent and he's lovable and he's full of  
6 energy, and he and I kind of have a war going on, I put up  
7 a fence, he finds a hole; I fix the hole, he finds another  
8 hole; I get all the holes fixed, he finds he can jump up  
9 on a five-foot wall and pursue his self-interest which is  
10 to leave the yard. I put a fence up and finally we get  
11 that taken care of, I put him on a leash, go down to the  
12 bakery, go in and get my coffee, come out, he's chewed the  
13 leash free and is going again. I think I just described  
14 the last 80 years of utility regulatory regulation. And  
15 the paradigm that I'm going to express this in is that we  
16 made a Faustian bargain 80 years ago, the goal of the last  
17 century was to provide reliable electric service to all  
18 the population. We achieved that goal, we did it in a way  
19 that said we'll give you monopoly control over everything,  
20 we'll guarantee your profits, you don't have to face  
21 competition, but we're going to regulate you. And what  
22 I've heard all morning and, unfortunately, what I've heard  
23 for the 35 years that I've been in this business so far,  
24 is that there is absolutely nothing that the utilities  
25 perceive to be in their self-interest of putting in

1 distributed generation, quite the contrary. And they drag  
2 their feet and they do it out of self interest. And it's  
3 not that they're immoral or anything else, it's just that  
4 the self-interests aren't aligned. And so my suggestion  
5 is that the future is going to be described by a word that  
6 starts with "D" and it'll either be distributed  
7 generation, or it will be disaster. And I don't think  
8 there's any other words.

9           Why I say that is that the CO<sub>2</sub> comes 69 percent  
10 from making heat and making power, and as long as we  
11 continue to do that with two fires, we throw away two-  
12 thirds of the energy making the electricity, and then we  
13 throw away all the work on the other thing. The only way  
14 we can do that with one fire is to have distributed  
15 generation, good quality CHP and, most importantly, waste  
16 energy recovery which was not covered in the options this  
17 morning and probably adds 1,500 megawatts to what you saw.

18           So with that in mind, I'll try and give some  
19 quick comments here. The good -- the goal of another  
20 6,500 MW, terrific, in removing the Settlement issue,  
21 that's been blocking everything for four or five years and  
22 I'm glad to see it. The Self Generation Incentive Program  
23 has a real opportunity to start something bigger in  
24 California. The sub-five megawatt range has always been a  
25 challenge to developers because there's so much

1 transaction cost and so much difficulty and, if you add  
2 any transaction cost to it at all, you kill the deal and  
3 it's chicken and egg because you never get enough of it  
4 going that we start to overcome all of the lessons and get  
5 better at it. And so I think your SGIP might break that  
6 chicken and egg cycle, I would be surprised not to see  
7 some developers -- we are coming at it hard with our back  
8 pressure steam turbine division making some significant  
9 commitments, and I think that's helpful.

10           The feed in tariff removes a lot of the  
11 uncertainty for hosts, it takes us anywhere from one year  
12 to three years from the time we first knock on a door of a  
13 host, before we reach a contract. And you don't want to  
14 spend all that money doing that if you don't know at the  
15 end of the day that you can get a contractor that's going  
16 to be worthwhile. So I think that's the good.

17           Problems. And the problem is that we haven't  
18 figured out how to train Guido with a carrot; we try to  
19 control Guido with a stick and utilities very  
20 intelligently employ floors and floors of people to figure  
21 out how to find another hole in the fence, and how to slow  
22 things down that they don't want to do, and what's not in  
23 their self-interest.

24           The standard interconnection process seems to be  
25 broken. It's always been raised as a technical issue,

1 it's not, it's a commercial issue, not that you don't have  
2 to think about it, but it's a commercial issue. Now they  
3 push off to the ISO who doesn't think they have any  
4 customers and can take up to five years to figure out  
5 whether you're going to have transmission. The utility  
6 says that's great, it'll stall this project for another  
7 five years and we'll go from there. There's a number of  
8 grid benefits that CHP can produce and I'm going to talk  
9 about them, but they're ignored by everybody and, if I  
10 leave you a second message besides the paradigm switch,  
11 it's let's look at some of these benefits and see if we  
12 can't capture them.

13           The CARB deliberations have really put a chill  
14 on things. I'm going to be perfectly blunt, I think that  
15 the proposal to cut everybody to zero emissions and then  
16 charge everybody and spread the money around later is just  
17 a bad paradigm. It would be so easy to fix by giving  
18 everybody the average and, if you're cleaner on an output  
19 basis, you've got things to sell; if you're dirtier,  
20 you've got things to buy, and the market will clear. But  
21 we've created lots and lots of problems, and the hosts  
22 that we're talking to say, "I don't want to proceed with  
23 this because the way I'm reading the rules, I might have  
24 to pay more for carbon if I do the right thing. If I cut  
25 the total environmental footprint of making my heat and

1 power with CHP, I'll have to pay more for carbon. And  
2 they don't like that.

3 CARB continues to do what it's done since its  
4 inception, which is to put the biggest burden on clean air  
5 on the new plant, so you're constantly in the business  
6 when you build a new plant of having to spend more to cut  
7 your pollution down, and then compete with people who have  
8 grandfathered permits. And, you know, until we move to  
9 output-based pollution allowances that apply to everybody,  
10 we're going to continue to have that problem. So that's  
11 the bad.

12 How can California speed societally profitable  
13 deployment of clean energy? My feeling is the goal is not  
14 clean energy and the goal is not cheap energy, the goal is  
15 clean cheap energy. We need to do this in a way that  
16 actually cuts the cost down, and any standard less than  
17 that, we're being lazy, it's not going to work. So we as  
18 a company and me as an individual for 35 years have been  
19 focused on ways to get more value. I think the first  
20 thing is you've got to find ways to reward the utilities  
21 for supporting distributed generation and for improving  
22 their efficiency. All I need to know as a fact is that  
23 the utility efficiency in the United States has not  
24 increased by one percentage point in 50 years. During  
25 that 50 years, we had an unbelievable technological



1 advance in everything else, and utilities are still where  
2 they were when Ike left the White House. I need say no  
3 more. We've got to figure out a way to put this stuff in  
4 that's twice as efficient.

5 I think that you should deeply consider programs  
6 for encouraging all utilities to interconnect up to about  
7 20 MW into the distribution system. The reason for that  
8 is that there are benefits that can be given to the  
9 distribution system by local generation, and I'm going to  
10 talk about them in a minute. You can't get those benefits  
11 going right to the transmission, plus it costs more.

12 I'm going to suggest ways that we can look at  
13 targeted CHP to provide voltage support to the  
14 transmission lines, and we've got significant academic  
15 support and almost no argument that we could cut the line  
16 losses in this country down by 60 percent. To calibrate,  
17 we spent \$26 billion on line losses last year in the  
18 United States, and it took about 165 million metric tons  
19 of carbon to create the energy that we lost in the lines.  
20 And the best kilowatt is the one you don't ever make.

21 Finally, I'm going to suggest that you could  
22 develop a program for long term contracts that would  
23 induce oversized CHP plants to provide spending reserves.  
24 I'm not talking about a PURPA machine that can feed you  
25 simple cycle power around the clock, I'm talking about a

1 machine that runs thermally matched, at its discretion,  
2 and runs full out at the grid's discretion, to cover the  
3 wind.

4           So, in the very short time, let me try and touch  
5 those just at a high level. Carnegie Mellon studies show  
6 that local generation connected to the distribution system  
7 can substantially lower the line losses. We've heard this  
8 morning about the problem that there's these system  
9 charges and they probably are too high, but there's no  
10 question but that there should be some system charges; the  
11 utilities shouldn't have to subsidize the non-utility  
12 player. But let's ask the other question: why should the  
13 non-utility player have to subsidize the utility or the  
14 public? And yet that's exactly what we do. Let's go to  
15 the math. If you're just connected to the grid, well, if  
16 you're just off the grid, you're going to produce 6.5 to  
17 7.5 percent line losses because you don't have line losses  
18 when you're going right to the load. If you're connected  
19 to the grid, that means that you're also going to lower  
20 the power flowing through the lines to everybody else, and  
21 you get a tiny line loss savings on all of that, but you  
22 multiply it by all the power. And so in the range of zero  
23 to 20 percent of load from distributed generation, you  
24 about double the line loss savings. A good operating  
25 number is 14 percent.

1           What this means is that every megawatt hour of  
2 local generation running over the course of the year will  
3 on average avoid 1.14 megawatt hours of central  
4 generation. And yet we look at a heat rate that assumes  
5 that the megawatt that was made a long ways away and had  
6 to ship is exactly the same heat rate as the megawatt that  
7 was made locally -- not true.

8           It gets better. The problem with the electric  
9 system is what it does. When you make electricity, it  
10 goes one of four places, and only one of them is good.  
11 The one that is good is it gets to the user. The one  
12 that's definitely bad is its line losses. The one that is  
13 a mixed bag, the two that are mixed bag, is that it will  
14 make a magnetic field and it'll make an electric field.  
15 If that was the end of the story, we probably wouldn't  
16 have a universal electric system because we'd be losing  
17 everything in all this loss, but the good news is the  
18 magnetic and the electric field cancel each other out, and  
19 you get all that power back out *if* they're balanced.  
20 They're never balanced, except by coincidence because  
21 loads change, it goes up and down, and so forth, number  
22 one. Number two, you cannot ship the balancing bars down  
23 the wire. You can go back up the wire, but you can't go  
24 down the wire, it's physics.

25           What Dr. Ehrlich at Carnegie Mellon has found

1 and then proven on an island in Europe is that, by hooking  
2 up a megawatt of distributed generation and giving the  
3 Grid Manager the right to control the power factor -- and  
4 I'm talking about controlling it Internet real time -- I  
5 need a little more leading or lagging power fact, but  
6 depending upon where it was placed you could on average  
7 eliminate 1.25 to 1.45 MW hours of central generation for  
8 every MW hour that you do locally. There is a little cost  
9 locally because you're making megavars, so you don't make  
10 quite as many megawatt hours, but the numbers are  
11 fantastic, it is worth way more than the megavars that the  
12 big plants sell to each other because it's at the back end  
13 of the line, you can balance.

14 That's the average. Now it gets really good  
15 when you think about system benefits. During the peak,  
16 that megawatt hour with var support that's run by the  
17 grid, can avoid 2 to 2.5 megawatts of central generation.  
18 You don't have very many hours of peak, so the actual  
19 avoidance of the generation is not the big piece of  
20 economics. The big piece of economics is that we design  
21 our systems against the peak -- that's what we build the  
22 wires for, all that investment, that's what we build the  
23 peaking generation for, all that investment. So every  
24 time we put in a megawatt hour, a megawatt capacity now,  
25 of distributed generation, and have it hooked up to give

1 power factor support, we can cut the need for investment  
2 in the system down by two megawatts to 2.25 megawatts, and  
3 that's a lot of money to flow through the system before  
4 it's done.

5 Let's go back to self-interest. Is that of  
6 interest to the utilities? I can't think why. They get  
7 paid a return on invested capital, you've just cut down  
8 the need for capital. The paradigm is broken. You're not  
9 going to get there without changing the paradigm.

10 Okay, let's go to the next thing. We have in  
11 California a big market and a lot of power comes into  
12 California, a lot of the cleanest power comes from the  
13 northwest, but we have a problem with wires. Now, I don't  
14 know if the wires will be built, I'm too old, I don't  
15 think I'll ever live to see the wires built, some of you  
16 young folks might see it, but it's a long time away. We  
17 have had a situation in the last two years where BPA is  
18 dumping power and saying, "I can't take the wind." "Shut  
19 your windmill off, I can't get it in." We've had clearing  
20 prices in certain times of a minus \$20.00, BPA paying  
21 people \$20.00 to take a megawatt hour because they can't  
22 shift it. Well, what are we going to do? We've got  
23 power, we need the power, and we don't have enough wires.  
24 Have the CAISO look at the node and go along and say, "I'm  
25 going to put these things in periodically on the

1 transmission lines, I'm going to provide voltage support,  
2 the lines are not thermally loaded, they're almost all the  
3 time loaded against voltage drop when the voltage gets  
4 down so low you can't go any lower, and so it would be  
5 like giving those lines steroids.

6           Finally, I think that what you've got to do to  
7 do this is to have regulations that will induce line loss  
8 savings. They've got to be reflected in CHP payments and  
9 credits. Right now, the line loss savings go 100 percent  
10 to the public, and that's why there aren't any. You get  
11 what you pay for. The next worst thing you could do is  
12 give it all to the CHP developer because the utility would  
13 fight it all the way, they're not getting anything out of  
14 it. The best thing, give some to the CHP plant, give some  
15 to the utility, give some to the public, let's come to the  
16 dance and ask Senator Shaheen's question that she's been  
17 asking us at the national level, "What can we do to make  
18 CHP attractive to all the players?" Let's get out of the  
19 war, figure out how to make it attractive. Incentivize  
20 the utilities to connect DG at their level, CAISO will  
21 offer some long term contracts and get this stuff done.

22           The last piece that I want to bring up is that  
23 we're increasingly needing spending reserves and it's a  
24 problem that's on everybody's mind. This is a picture of  
25 the hourly wind output over a month of August in Ontario,

1 that's a pretty big territory, and you can see that it's  
2 all over the map. You just can't count on the wind being  
3 there at any particular time and, so, it's more variable  
4 and we're losing baseload. Each megawatt of renewables  
5 rewires more megawatts of reserve. Well, what do you do?  
6 Of course, first of all, you use the hydro and stored  
7 water and so forth, but when you run out of that, you have  
8 to do something else, so the conventional answer is, after  
9 you've used the hydro, you put simple cycle gas turbines  
10 and cause them to run at about a 40 percent load and a  
11 13.5 thousand Btu heat rate. They run maybe 3,000 to  
12 4,000 hours; if they don't now, they will tomorrow  
13 because, as there's more wind, you need more spending  
14 reserve and it's really a problem. It adds 6,000 to 7,000  
15 Btus of cost and emissions as a penalty to the wind.  
16 Let's think about doing that a different way. You build  
17 an oversized CHP plant. I want to talk about a cheese  
18 plant two hour drive from here. A 20 megawatt turbine  
19 would be perfectly matched with their load, their thermal  
20 load, and they need about 15 megawatts, so you'd be  
21 exporting five or trying to make it work, and that will  
22 take you four years to work that out, you heard the story  
23 this morning about the export. Instead of that, put a 50  
24 megawatt turbine in. When you run it at 15 megawatts part  
25 load, it's so inefficient that you'll get all the heat you

1 need because you're getting more heat out of 15 megawatts  
2 of a big turbine at part load than you are out of a small  
3 one at full load. So you've kind of got a match between  
4 the electric load and the other, and you as the owner have  
5 the right to run that thing up to thermal match, and no  
6 greater. The grid has the right to ask you to run to 50.  
7 Whenever they do ask you to run to 50, they've got to pay  
8 the incremental cost of you doing that, which are the same  
9 as if you ramped up the turbine. The net value of all  
10 that saves Btus both ways, encourages 4,500 Btu thermally  
11 matched CHP. In order to get there, and I just go on to  
12 the benefits and come back to that, we've looked at 120  
13 megawatt wind farm. A part load electric plant only  
14 burning an incremental 4.3 million Btus of fuel a year to  
15 back up that wind field, using that identical turbine or a  
16 series of smaller turbines in CHP mode, part load, saves  
17 7.7 million, that's a \$12 million a year swing to society,  
18 that racks up to a \$34.00 a megawatt cost to society. You  
19 don't see the whole \$34.00 because you don't have the  
20 comparison of it being not there, but that's the benefit  
21 that's there, that allows us to sort of cut through and  
22 say, "Jeez, let's share these benefits." And I say,  
23 unless some of it is used to incentivize the developers,  
24 why would we put in 50 megawatts of capacity on the hope  
25 that somebody might buy? We need a long term contract.



1           If I go back for just a minute to the regulatory  
2 changes, the ISO has got offer long term contracts for  
3 spending reserve to get this, you don't need to on the gas  
4 turbines, the simple cycles are sitting out there for  
5 peaking, you just run them more often, it's -- that's the  
6 kind of policy it is. You need to modify the feed in  
7 tariff rules so that the 20 megawatt limit applies to the  
8 thermally matched part that you're allowed to run and you  
9 don't get this thing canceled out because you also  
10 provided something to provide the spending reserves. And  
11 you're certainly going to have to incentivize the  
12 utilities. Why should they do this? If it doesn't make  
13 them anymore money, all we're going to get is foot  
14 dragging.

15           My conclusion, California is already a leader in  
16 CHP, you've moved strongly to the transition to a 21st  
17 Century electric system, but it's a war, everybody drags  
18 their feet, got nice words to put around it, but the fact  
19 of the matter is, every CEO of the utility says, "I've got  
20 five years? Let me put this off as long as I can, leave a  
21 note in the drawer when I leave, I did my job, you put it  
22 off as long as you can." It's good for everybody but our  
23 children and our grandchildren.

24           I think the new programs that you're doing is  
25 going to attract some smaller scale developers and that's

1 a good thing. I don't know how you split these  
2 responsibilities between the agencies, but we have to  
3 shift the paradigm. We've got to begin rewarding  
4 utilities to do this. I can't train my dog with the  
5 stick, I've got to give him a kibble when he shakes hands  
6 and then I've got a good dog and he's smart and I love  
7 him, and the utilities are smart and I love them, but  
8 they've got the wrong incentives.

9           The CARB rules, I'm sorry to say, are a  
10 disaster. Just give everybody the average CO<sub>2</sub> output per  
11 unit of output and let the market figure it out. You  
12 record your output, there's so much CO<sub>2</sub> you had to have,  
13 oh, by the way, next year you get less; and then all this  
14 stuff goes away.

15           We need to encourage the CHP spending reserve  
16 plants with long term contracts. We need to encourage the  
17 support along the lines because it's a way to build  
18 transmission lines without 20 years of intervention.

19           And finally, I would suggest that if this looks  
20 daunting, consider the experience in Denmark. In the mid-  
21 '80s, their system was all central stations, a few big red  
22 dots; 20 years later, they got a system that's something  
23 like 54 percent delivered efficiency vs. our 33 -- this is  
24 a trading partner, we can do this, it's something that we  
25 -- it's too important not to do it and be caught in

1 another 30-year war fighting over who gets paid. My slide  
2 is blocked. Well, the last slide said thank you, so thank  
3 you.

4 CHAIRMAN WEISENMILLER: Thanks, Tom. A couple  
5 questions. First, you mentioned some Carnegie Mellon  
6 Studies on benefits of DG. Could you at least point us to  
7 those studies so we can get those in our record?

8 MR. CASTEN: I will, indeed.

9 CHAIRMAN WEISENMILLER: And the other one is you  
10 mention Denmark. My impression is that one of the  
11 regulatory changes in Denmark that really led to the  
12 differences between 1980 and now was basically utilities  
13 stepping in to at least develop some other projects  
14 themselves?

15 MR. CASTEN: That was the effect, Mr. Chairman,  
16 but my understanding of how it works is the following. In  
17 -- right after the second OPEC crisis, Denmark almost went  
18 bankrupt. They had 78-80 percent of their total energy  
19 input in the form of oil, and that price of oil suddenly  
20 went up four times and the country was in a bit of a hole.  
21 They put a huge tax on all fuel and then they said if your  
22 plant exceeds this efficiency level, you don't have to pay  
23 the tax. And the only way you could get to that  
24 efficiency level was to recover the heat that you'd been  
25 throwing away and do something with it. So they did a lot

1 of things, but they did not sort of say "the utilities  
2 can't do this." Now, their utility structure is a little  
3 different, it's almost all municipals, they don't have the  
4 big investor-owned IOUs as much. But, yes, they did allow  
5 the utilities to come in and do it, and they closed down  
6 some big plants, they took heat out of the big plants,  
7 they developed District heating, and you can see what  
8 happened. The irony is that they actually got so far that  
9 when the North Sea Gas came in and we got the lines coming  
10 down from Norway, they actually had too much power for the  
11 lines because they're getting hydro, which is even  
12 greener, but Denmark is a little worried about sea level  
13 rise from Climate Change for some reason I don't  
14 understand because there are a lot of places in Denmark  
15 that are at least five meters above the sea level.

16 MR. RECHTSCHAFFEN: Tom, are there any ISOs that  
17 have adopted the kind of tariffs you're talking about?

18 MR. CASTEN: We have seen a maximum of a one-  
19 year contract for spending reserve, and most places, they  
20 don't even talk to you. The PJM, I think, designates who  
21 is going to provide spending reserves a month at a time.  
22 The argument is made that all we need is a price signal  
23 and that everybody will satisfy it, and if you're just  
24 bidding between existing capacity, that's probably true,  
25 but it doesn't induce new capacity. My second ISO

1 experience, which is also negative to your question, sir,  
2 is that the New York ISO has a market for vars and they  
3 believe their market satisfies everything, and it's a very  
4 -- you know, if you're a big plant, you can make a few  
5 million dollars by selling VARS, but they won't flow  
6 downhill and they don't recognize that it's worth a  
7 different value. It's like saying, I'm in Chicago in July  
8 and I want an ice-cream cone, and I can buy it for one-  
9 third of the money in Juarez, but it won't help me a lot  
10 because I can't use it in Chicago. And they just have not  
11 recognized that those VARS have a different level of  
12 importance, depending on where they come from, and so by  
13 and large this hasn't been done.

14 CHAIRMAN WEISENMILLER: One other question is,  
15 you had mentioned potential of, I think, 15,000 for CHP  
16 designed around waste heat?

17 MR. CASTEN: Fifteen hundred.

18 CHAIRMAN WEISENMILLER: Fifteen hundred, okay.

19 MR. CASTEN: We've identified 500 MW that could  
20 be done with back pressure steam turbines, where the host  
21 is presently dropping the steam pressure down and just  
22 throwing the work away from it. Based on our studies at  
23 other places, we think there's at least another thousand  
24 where you're taking waste heat from a process, or off gas.  
25 I mean, I drove by Valero on the way up here and there's

1 all those flares -- it's nice to look at it at night, it's  
2 real pretty, but that's all energy that could be converted  
3 into, you know, recycled into waste energy. So I think,  
4 altogether, I might add 1,500 MW to the numbers that our  
5 friends at ICF put up by including waste energy.

6 CHAIRMAN WEISENMILLER: And the basic -- the  
7 three most important policy measures we'd have to take to  
8 get to waste heat?

9 MR. CASTEN: I actually think the SGIP is going  
10 to cause the back pressure turbines just like it is, it's  
11 a sweet spot and that's going to happen, then you don't  
12 have to get an interconnect. To get to the rest of it,  
13 we're going to have to sort these things out that don't  
14 take you four years to get an interconnect and drag your  
15 feet, so forth.

16 CHAIRMAN WEISENMILLER: Thanks. Questions?

17 MR. NEFF: Thank you, Tom. The next presenter  
18 we have is John Ballam who is going to be presenting via  
19 WebEx. So I direct you to the slides as opposed to a  
20 presenter. John, can you hear us?

21 MR. BALLAM: Yes, I can. Can you hear me?

22 MR. NEFF: Yes, we can.

23 MR. BALLAM: Great, great.

24 MR. NEFF: I would say speak up if you can, it's  
25 a little quiet on that side.

1 MR. BALLAM: How's this?

2 MR. NEFF: That's great.

3 MR. BALLAM: I'll turn off the mic here. Is  
4 that better?

5 MR. NEFF: That works. Thank you.

6 MR. BALLAM: Well, it's nice to be with you,  
7 it's been very listening to the comments and -- just to  
8 give you a feeling of comfort, you know, because you might  
9 be worried that I'm speaking from the other coast, I was  
10 born in Berkeley. So with that introduction, I'd like to  
11 say a few words about what we're doing here in  
12 Massachusetts, alternate energy standard --

13 MS. KOROSEC: John, you're cutting in and out.

14 MR. BALLAM: Oh, sorry. I don't know if it's  
15 the phone or what. How is this?

16 MS. KOROSEC: That's good.

17 MR. BALLAM: Well, if it continues to cut in and  
18 out, let me know and I'll -- I don't know what I can do  
19 about it, but I'm on a land line. Does that still -- is  
20 that still doing it?

21 MR. NEFF: It sounds good, I would say continue  
22 and we'll stop if it gets bad.

23 MR. BALLAM: Give me a red flag if it's a  
24 problem.

25 MR. NEFF: All right.

1           MR. BALLAM: So let's see, for some reason my  
2 slide is not -- oh, there we go. Okay, so in  
3 Massachusetts, a general overview here, we have two  
4 incentive programs -- well, first of all, at this time we  
5 have two incentive programs that have resulted in 50  
6 megawatts additional operating CHP projects since their  
7 inception. Both of them began in 2009. One of them is a  
8 utility administered efficiency plan which is part of the  
9 overall efficiency plan which is funded by on bill by  
10 ratepayers. It's a front end benefit, i.e., capital, it's  
11 at \$750.00 per kilowatt hour -- I'm sorry, not kilowatt  
12 hour -- kilowatt capacity, and for under 150 KW with a  
13 maximum incentive of \$112,000. And above 150 KW, it's at  
14 the discretion of the utility program administrators. All  
15 the mid-size projects, the caps usually (inaudible) larger  
16 systems -- is it still cutting out?

17           MR. NEFF: Yes, it is.

18           MR. BALLAM: Oh, gee. I don't know what I can  
19 do about that. Also, it doesn't -- my slide --

20           MR. NEFF: You don't have to indicate, I can  
21 find the slides here, so just send the next slide.

22           MR. BALLAM: Okay, thanks. So for the large  
23 systems, the cap is sliding and is basically measured  
24 against remaining funds and the need to distribute them.  
25 Eligibility, the as designed system efficiency has got to



1 be greater than 60 percent, and it's got to pass a cost-  
2 effectiveness screening threshold established by our DPU,  
3 resulting in a benefit to cost ratio of greater than 1.  
4 And here, the benefits are basically system benefits,  
5 avoided energy and system costs, and also some non-energy  
6 benefits. Next slide, please.

7           There's a link there to a document that will  
8 give you a lot more information about that. The State has  
9 got two Portfolio Standards in place at this time, a  
10 Renewable Portfolio Standard which covers solar and wind,  
11 and renewable fuels, and an Alternate Energy Portfolio  
12 Standard which specifically includes CHP, which is what I  
13 will focus on today.

14           In general, the benefit here is that it provides  
15 -- or its intent is to provide a program structure for  
16 scheduled growth of both capacity and related incentives  
17 levels needed to ensure CHPs, that we meet the goals that  
18 are set by high level legislation such as the Green  
19 Communities Act, and the Global Warming Solutions Act,  
20 which I think are somewhat analogous to your AB 32, and in  
21 a way that is predictable. The APS is a production  
22 (inaudible) administered by the Massachusetts Department  
23 of Energy Resources (inaudible), which are called  
24 Alternate Energy Credits, or AECs, is earned per megawatt  
25 hour of net source fuel energy saved by CHP unit, and I'll

1 cover how that's determined in another slide, at a greater  
2 than 200 KW, are required to have (inaudible) grade KWH  
3 Btu and fuel meters, and the meters are read by  
4 independent parties. All of the projects that have  
5 received a utility incentive are also enrolled in the APS,  
6 so the programs are fairly complementary.

7           Going further into detail, (inaudible) S, it  
8 creates an obligation (inaudible) probably your Renewable  
9 Energy Standards and (inaudible) all the retail  
10 electricity suppliers are load serving entities  
11 (inaudible) equal to a set minimum standard of the load  
12 served, percentage. And purchase of the AECs from the  
13 qualified generators buys an additional revenue stream  
14 (inaudible) and the purpose is to incentivize and  
15 recognize net GHG reduction and fuel savings, also some of  
16 the other benefits that Tom was -- system benefits that  
17 Tom was mentioning before.

18           Regulated Suppliers, the IOUs, can recover the  
19 cost of the obligation (inaudible) rate cases. The  
20 competitive suppliers don't have this cost recovery path.  
21 Next slide, please.

22           The APS was established under legislation called  
23 the Green Communities Act in 2008. (Inaudible) began in  
24 2009 (inaudible) qualified units produced AECs. Also, the  
25 APS also includes other technologies, but these have not -

1 - CHP is (inaudible) look to produce almost all of the  
2 credits to be generated in this program. (inaudible)  
3 basically it is incentivizing net source fuel savings, as  
4 all of you are, I'm sure, very familiar, you (inaudible)  
5 efficiency (inaudible) CHP at (inaudible) fuel by a unit  
6 of energy (inaudible) takes for a local boiler to supply  
7 -- to meet the load, that's a certain amount of fuel. If  
8 you look at fuel at a CHP unit, it requires to meet the  
9 same loads, electrical and thermal load. It takes less  
10 fuel and so there's a net fuel savings associated  
11 (inaudible). A formula that we use is that (inaudible),  
12 so in the ISO New England area, it just turns out  
13 (inaudible) average heat rate and the line losses, it  
14 comes out to almost exactly .33. Megawatt hours of  
15 electricity metered (inaudible) Btu meter divided by .8,  
16 sort of the average for a conventional thermal conversion  
17 unit, minus the fuel that the CHP put in, and that's how  
18 many AECs you get per megawatt of fuel savings, megawatt  
19 hours.

20           Governing Regulations -- you can download those  
21 and take a look at them. (inaudible) cutoff dates -- new  
22 systems, only those that started up after January 1st,  
23 2008 (inaudible) didn't want to incentivize older  
24 (inaudible) there's a provision for incremental load or  
25 modifications. Payment mechanism, certificates are

1 traded, so meter readings are taken, they're submitted to  
2 the NEPOOL GIS, they (inaudible) certificates, the  
3 certificates are traded, and usually the settlement -- the  
4 minting and the settlement are one-quarter apart. Next  
5 slide.

6 Obligation Schedule (inaudible) 2014, but we are  
7 trying to meet half a percent increase per year of the  
8 load.

9 Some results, economic benefits. Our systems  
10 (inaudible) is 50 to 1 megawatt projects. For these  
11 systems, the APS alone is not sufficient to ensure the  
12 financial viability. However, the utility benefit when  
13 combined with the APS is usually -- will actually result  
14 in a pretty significant improvement in both payback and  
15 the ROI and is often enough to push the project over the  
16 threshold.

17 Projects greater than a megawatt, APS is the  
18 more significant factor due to the cap limitations on the  
19 utility administered incentives. Source Fuel Savings --  
20 so from 2009 until September 2011, we generated about  
21 600,000 AECs. (Inaudible) environmental benefits -- next  
22 slide, please. Next source GHG reduction, of course,  
23 they'll be specific to the emission coefficient of the  
24 regional grid system. For Massachusetts, the average grid  
25 emission factor right now is about 828 pounds per megawatt

1 hour. And for our grid in natural gas fueled CHP system  
2 (inaudible) about an 18 percent net reduction, about .078  
3 short tons per AEC. (Inaudible) a net reduction of  
4 approximately 46,000 short (inaudible). Next slide.

5 So impact to stimulation of CHP (inaudible)  
6 Massachusetts. Total CHP capacity here is (inaudible)  
7 SCIA is about a gigawatt (inaudible), about a gigawatt of  
8 that are central plants, central power stations, all pre-  
9 2008. And of that, almost all of them are greater than  
10 230 megawatts. And I should say on the side, one of  
11 those, I'm not sure, is still a cogenerator, but at least  
12 it's listed as one. (Inaudible) APS installed capacity of  
13 50 megawatts is only six percent of the total installed.  
14 (inaudible) APS represents, but (inaudible) percent of all  
15 CHP installations post-2008. So what happened here is  
16 that these large CHP projects basically dropped off the  
17 face of the earth (inaudible) or well (inaudible). All of  
18 the post-2008 plants have been smaller than 25 megawatts  
19 with a large majority under 500 KW. Of those, of these  
20 new post-2008, the APS has been a major factor in  
21 successful progress to completion for those projects.

22 (Inaudible) they're concerned, obviously, we  
23 would like to see -- we would like to see a faster  
24 (inaudible) of CHP here in Massachusetts and some of the  
25 factors which have (inaudible) listed some of them here,

1 and this is by no means a complete list. One of the major  
2 ones is lack of access to capital due to the economic  
3 conditions since 2008. Another one is the complex  
4 information requirements to qualify for the utility  
5 administered benefit. That really flows out of the fact  
6 that the benefits are predicated on avoided cost, a lot of  
7 which are heavily weighted towards being able to ensure  
8 that these systems are going to be running during peak  
9 summertime, which here in Massachusetts often coincides  
10 with a lack of a thermal load, so there the utilities like  
11 to see almost hour by hour thermal data, historical data,  
12 which is not always easy to come by. The existence of  
13 conservative stand-by tariffs in one of the major utility  
14 service areas -- this possibly will be being relaxed due  
15 to a settlement that was reached yesterday. So really,  
16 this next bullet doesn't belong here, so let's forget it,  
17 my fault. Lack of a Federal Investment Tax Credit large  
18 enough to spur limited partnership invested by third  
19 parties. When we compare growth of CHP and the mechanisms  
20 for financing it with our PV solar program here, the  
21 difference between the 10 percent and the 30 percent is a  
22 large factor in being able to round up investors.

23           Given all of that, the APS has been a major  
24 factor in successful progress to completion. A couple of  
25 other factors are limited effective coordination between

1 the two State programs, and I caution you folks there in  
2 California to pay attention to the difficulties sometimes  
3 of tying programs together so that they actually operate  
4 in concert as they were supposed to. And, again, the slow  
5 acceptance of CHP benefits by the utility programs, they  
6 are still rather hesitant to accept the fact that CHP can  
7 be counted on when it's needed. Next slide. I lost my  
8 slides here, so hold on a second, sorry. There we go.

9           Some possible relevance to what you folks are up  
10 to in California. So the two Massachusetts programs, and  
11 particularly APS, have been recognized by the people in  
12 the sector, the participants, as successful insomuch as  
13 they have been -- the projects that have been completed  
14 would not have been completed for the most part without  
15 them. But the other factor I mentioned, the other  
16 inhibiting factors can combine to, you know, overcome the  
17 push and the progress that could be, oh, very important  
18 once this legislation is passed, whatever it might be, if  
19 it's (inaudible) Portfolio Standard, that one doesn't back  
20 away with it and think, "Well, there, I solved the  
21 problem, I've got a (inaudible), I've got a schedule, I've  
22 got an incentive, and everything should just proceed  
23 (inaudible).

24           (Inaudible) a look just for your information of  
25 how our projects are distributed by end use (inaudible) of

1    them are either industrial or (inaudible). A couple of  
2    our large campuses have gone ahead and put in gas  
3    turbines, have a couple of rather, you know, a few  
4    (inaudible). However, in terms of pure numbers, the  
5    (inaudible) 5 megawatts has a lot more projects.  
6    (Inaudible) some by system type, (inaudible) interest, I  
7    won't cover that, final page is some of our contact  
8    information here in Massachusetts and we would be very  
9    glad to (inaudible). And I did put in an appendix here  
10   with more details, more program-related details on an  
11   administration quality assurance and things of that  
12   nature, which might be of interest to you if you are  
13   considering this type of a program. That concludes my  
14   presentation.

15               CHAIRMAN WEISENMILLER: Thank you very much.  
16   This is Chair Weisenmiller. A couple questions, the first  
17   one was you mentioned that there were some other  
18   technologies that were eligible under the APS, but have  
19   just not happened. What were those technologies?

20               MR. BALLAM: The major one were flywheel storage  
21   and it turns out, for whatever reason, we've only had four  
22   megawatts of flywheel storage installed under this  
23   program, were applying, improved and installed, and  
24   actually that particular company that was doing that has  
25   since gone under. There was another rather ill-defined



1 technology called Advanced Steam Technologies and, to be  
2 frank, I don't think anybody quite knows what that means.

3 CHAIRMAN WEISENMILLER: Okay, was that limited  
4 to flywheel storage, or storage in general?

5 MR. BALLAM: Flywheel storage, in particular.

6 CHAIRMAN WEISENMILLER: Okay. And just the  
7 other question which you may not know, I was just trying  
8 to understand what the value of RECs are now on NEPOOL?

9 MR. BALLAM: The value of RECs right now are --  
10 Class 1 RECs are almost at \$50.00.

11 CHAIRMAN WEISENMILLER: Okay, thanks.

12 MR. BALLAM: Yeah. Oh, I should mention, I  
13 didn't mentioned, but I should mention that our program  
14 allows a combined heat and power system that is  
15 (inaudible) both the AECs and the RECs, which right now  
16 would amount to about 8 cents per kilowatt hour.

17 CHAIRMAN WEISENMILLER: Great, thanks again.  
18 Any other questions? Sure.

19 MR. BIERING: Brian Biering with Ellison,  
20 Schneider and Harris. I'm here on behalf of Aceco  
21 Generation and Rio Bravo. I have more of a general  
22 comment about the --

23 CHAIRMAN WEISENMILLER: Why don't you hold the  
24 general comment for the end?

25 MR. BIERING: Okay.

1           CHAIRMAN WEISENMILLER: These are specific  
2 comments for the person on the phone.

3           MR. BIERING: Thank you.

4           CHAIRMAN WEISENMILLER: Okay, thanks again.  
5 Let's go on to the next speaker.

6           MR. NEFF: Thank you, John. I have to apologize  
7 to the people in the room, WebEx was recording it, it had  
8 something to do with the speakers within the room, and so  
9 if you want to hear his full explanations uninhibited, I  
10 encourage you to go online once we have the recording  
11 posted.

12           And with that, I'll be turning it over to  
13 Rizaldo Aldas who is going to cover the next section.

14           MR. ALDAS: Thank you, Brian. Good afternoon,  
15 everyone. My name is Rizaldo Aldas, I am with the Energy  
16 Research and Development Division of the California Energy  
17 Commission.

18           This session is on the technology innovation in  
19 overcoming CHP barriers and what I will do here is just  
20 provide you a hopefully quick overview of the CHP RD&D,  
21 and then I will call two gentlemen who will be providing  
22 -- talking about specific projects that are funded under  
23 the program, the Public Interest Energy Research Program.

24           First, let me start with the policy drivers.  
25 All research programs under PIER are driven by policies

1 and these are just some of the policy drivers for CHP  
2 RD&D, and most of these, I think, have been mentioned in  
3 earlier talks. SB 1250 here provides specific investment  
4 categories for PIER funding. And among these is the  
5 Advanced electricity generation technologies that exceed  
6 applicable standards to increase reductions in greenhouse  
7 gas emissions from electricity generation, and that  
8 benefit electric utility customers.

9           The Scoping Plan under AB 32, as well as the  
10 Governor's Clean Energy Jobs Plan calls for a specific  
11 additional CHP capacity at a certain time. Now, those  
12 policies help us describe the overall goals for the  
13 program, and that is to advance the science and  
14 technology, reduce barriers and increase market  
15 penetration of CHP/CCHP, and to help achieve that goal we  
16 adopted some strategies such as expanding the CHP/CCHP,  
17 recognizing that CHP is the most efficient form of DG. We  
18 work on developing innovative energy supplies focusing on  
19 desirable qualities, including reducing polluting  
20 emissions, increasing energy efficiencies. We're looking  
21 at developing hybrid generation, fuel-flexible systems, as  
22 well as demonstrating diversified applications of CHP that  
23 use renewable resources.

24           In this slide, I tried to provide you an  
25 overview of the portfolio of CHP technologies funded by

1 PIER, by technology types. You can see here the  
2 reciprocating engines, category first dealing with  
3 reciprocating engine, including modifications,  
4 reengineering, that represents 27 percent of the funds.  
5 The work on the turbines are mostly on a microturbine such  
6 as fuel- flexible or biogas fuel microturbines,  
7 (inaudible) 36 percent funding the fuel cells. We have  
8 worked on high temperature fuel cells, renewable fuel  
9 cell.

10 And then the CHP renewable technology, I tried  
11 to lump all the other works not related with -- not  
12 directly related to fuel cells, or gas turbines, or  
13 engines into this category, and this includes work like  
14 emission control technology, those activities that are  
15 looking at integrating a CHP, novel controls for operating  
16 CHP, as well as the market analysis and databases included  
17 performance standard activities under this area. And that  
18 represents 20 percent.

19 And these projects have a common emphasis or  
20 goals such as reducing cost, demonstrating the system in  
21 California high efficiency, low emissions, and the  
22 reliability, availability, maintainability, and  
23 observability including following performance testing  
24 protocols.

25 Now in the next three slides, I'll try to give

1 you examples of some of the projects that we supported.  
2 You have heard about this project on a 100 KW engine BBEST  
3 power system, the one on the upper left side of the slide.  
4 The one on the lower left-hand side is on the emissions  
5 control technology. The next speaker will be talking more  
6 about this one.

7           The figure on the upper right-hand side of the  
8 slide represents the research on ongoing project that is  
9 looking at retrofitting microturbine to commercial scale  
10 fighter boilers in CHP applications, while the figure at  
11 the bottom right, represents our project where the  
12 contractor is developing and demonstrating microturbine-  
13 based CHP system for turbine oxidizers that are using  
14 industrial process to address VOC emissions. Now, this is  
15 another example of ongoing project with GTI and the aim  
16 for this is to develop cost-effective gas turbine-based  
17 CHP system that improves the overall efficiency, while  
18 meeting or exceeding the ARB 2007 Emissions Standards for  
19 distributed generation. This is targeted for a small to  
20 medium-size industrial boiler and one of the key  
21 innovations here is the use of natural gas-fired  
22 supplemental burner to allow low emissions without the use  
23 of expensive catalytic exhaust gas treatment. Right now,  
24 the project has completed at this time, it is conducting  
25 refinement of the system, as well as preparing for fuel

1 demonstration.

2           Now this other example is also an ongoing  
3 project, expected to be completed by the end of the month  
4 and this is an example of a CHP system running on  
5 renewable resource, specifically biogas. This is a  
6 project with Gills Onion Company located in Oxnard,  
7 California and being conducted with GTI. This project has  
8 successfully demonstrated conversion of the waste product  
9 or waste water from the processing of onion to generate  
10 biogas and then clean up that biogas and use that clean  
11 biogas to run a 200 to 300 KW molten carbonate fuel cells.  
12 One of the key innovations here is the cleanup and  
13 conditioning system for the biogas. The project is  
14 successful, it is serving as a model for the food  
15 processing industry in California, and the project is also  
16 receiving a number of awards. The benefits in terms of  
17 reduction in natural gas, as well as greenhouse gas  
18 emissions is also provided here.

19           Now, in this slide, I tried to summarize our  
20 major initiatives in two categories, one is on the  
21 combined heat and power and distributed energy resource  
22 technologies. These initiatives consist of several  
23 ongoing projects at different stages, some are nearing  
24 completion, some have developed designs, and some are  
25 doing field tests. And the goal for this initiative is to

1 demonstrate and develop innovative, efficient and cost-  
2 effective CHP technologies, develop low emissions  
3 technology, and then use alternative fuels such as biogas,  
4 flared gas and natural gas.

5           The other initiative here is the hybrid  
6 generation fuel flexible DG/CHP/CCHP where we are looking  
7 at integrating emerging multiple technologies and fuel  
8 flexibility. This is an ongoing solicitation, we released  
9 this on January 6th, and we expect to receive proposals by  
10 the end of this month. If you want more details on that,  
11 you can look at the details in the CEC website.

12           Now, looking forward, we anticipate that R&D on  
13 CHP will continue, further refine, and deploy the  
14 technology. There are some potential areas that we may be  
15 focused on such as accelerating the deployment of CHP in  
16 industrial, commercial, institutional and other new areas  
17 including food processing, manufacturing and retail.

18           We are also looking at the application of CHP  
19 for biogas and local renewable resources to reduce  
20 consumption of natural gas for heating and power systems,  
21 capturing the waste heat from various industrial  
22 processors. The application of CHP for associated gas  
23 such as those produced from oil and gas fields in LA Basin  
24 and other low-Btu gasses. And then, of course, continuing  
25 the innovations to further refine and improve such as

1 looking at improving the integration of systems with  
2 building and industrial processes, develop and demonstrate  
3 Smart Grid readiness, address renewable intermittency, and  
4 improve efficiency of reducing emissions.

5 Now, I will not go through these questions, I  
6 just want to point out that we have some questions that we  
7 included in the agenda. We will appreciate receiving  
8 comments from the public and that will help us move  
9 forward. And with that, I would like to call on the next  
10 speaker, Mr. Keith Davidson, President of DE Solutions,  
11 who will be talking about the project on Ultra Low  
12 Emission Control for Rich Burn Engines. Keith.

13 MR. DAVIDSON: Thank you, Rizaldo. DE Solutions  
14 is a small San Diego-based consulting firm and, among  
15 other things, we get involved with advanced technology  
16 development mostly with people involved in the combined  
17 heat and power industry. And I've had the fortune of  
18 participating in a number of projects that were sponsored  
19 in part by the California Energy Commission, and two of  
20 them I'm going to talk about today are ones that were  
21 directed at significantly improving the emissions profiles  
22 on rich burn engines. And rich burn engines generally are  
23 less than or equal to about one megawatt in size. Rich  
24 burn engines are those where you operate at Stoichiometry  
25 exact oxygen, or exact amount of air and fuel, slightly



1 rich, actually. And then the larger size engines, over a  
2 megawatt, are typically what they call lean burn engines,  
3 which they put excess air in for some other advantages.  
4 But all engine technology has been extremely challenged by  
5 direction in air quality emissions in California. CARB  
6 probably started it back in the early 2000's when they  
7 adopted requirements for non-permitted prime movers to  
8 equal central station plant emission levels. And for  
9 permitted prime movers, which for the most part are  
10 engines and larger gas turbines, they issued guidelines to  
11 the local air districts because that was outside of their  
12 prerogative to force that. And so far, the South Coast  
13 Air Quality Management District about two years ago was  
14 the first one that implemented parts of the CARB '07  
15 Guidelines to engine technologies. And they actually  
16 adopted the NO<sub>x</sub> standard, not quite adopted the CL  
17 Standard, and I'll show you that a little bit later. But  
18 furthermore, there's a statewide requirement that, in  
19 order to get SGIP, in order to participate in AB 1613,  
20 you've got to meet the NO<sub>x</sub> requirement for CARB '07. And  
21 it's turning out that these levels are extremely low and  
22 very very difficult for reciprocating engines to achieve,  
23 so this was kind of the thrust of two R&D projects were to  
24 not only get down to those levels, but sustain performance  
25 at those levels without frequent testing, which really

1 means you have to be able to exceed the requirements.

2           And the two projects, real quickly, one was with  
3 my company, DE Solutions as the prime, with co-funding  
4 from SoCal Gas Company, and with Tecogen, who you heard  
5 from earlier this morning as being the primary  
6 subcontractor and manufacturer. The second project, the  
7 prime contractor was Southern California Gas Company, it  
8 was with a San Diego-based company that makes air fuel  
9 ratio controllers for engines and gas turbines, and I was  
10 part of that team. And, you know, the objectives I  
11 stated, to exceed requirements and to sustain performance  
12 without frequent operator intervention.

13           This just gives you a quick sense as to what --  
14 how difficult things have become. The BACT limit, which  
15 still exists for most of the state, is -- and the  
16 conventional metric, and the ones the Air District uses,  
17 are parts per million corrected at 15 percent oxygen. And  
18 it's 11 ppm for NO<sub>x</sub> typically and 70 ppm for CO. The CARB  
19 and South Coast, both have gone to an output-based  
20 standard, so it's per megawatt hour, and it does give you  
21 some credit to the extent you use heat, which is a good  
22 thing. But you can see when I translate the pounds per  
23 megawatt hour goals to parts per million, you can see how  
24 challenging it's gotten, it's maybe about a four-fold  
25 reduction in NO<sub>x</sub>, but the CARB levels anywhere, of course,

1 with a 10-fold reduction from the current BACT levels,  
2 which are really the biggest challenge.

3           If I can just take a second to -- this kind of  
4 frames the problem. In a rich burn engine with the three-  
5 way catalyst, like are in most automobiles, to the extent  
6 you have air in the exhaust, the catalyst is not going to  
7 be able to reduce the NO<sub>x</sub>. So on the left, you can see the  
8 NO<sub>x</sub> is real high, as you richen out the engine, add more  
9 fuel, the NO<sub>x</sub> comes down to very low levels. But at the  
10 same time, you've got a competing factor with carbon  
11 monoxide where, as you add a little bit more fuel and  
12 richen it out, it tends to shoot up and at that bottom  
13 line there, kind of triangle, you see sort of this really  
14 tiny point at what the CARB '07 rule, where the  
15 reciprocating engine has to perform at to stay in  
16 compliance. And that is a big part of the challenge.

17           Okay, so the two technology approaches, both  
18 teams of contractors pursued a number of different  
19 solutions and two really emerged, 1) Continental Controls,  
20 they've got a very precise air fuel ratio controller and  
21 so they build off of their core technology and included a  
22 number of other system improvements, including the use of  
23 NO<sub>x</sub> sensors, which is the first time ever really a NO<sub>x</sub>  
24 sensor was used on a rich burn engine for feedback, you  
25 know, post-emissions, post-catalyst feedback. They put in

1 a much more robust catalyst and used a technique called  
2 dithering, which is used a lot in the automotive industry.

3           Tecogen took a little bit different tact, they  
4 came up with an innovative catalyst configuration that  
5 widened the compliance window, that little tiny window  
6 that we showed you, they actually came up with an approach  
7 to just make it a lot easier to hit. And lastly, the  
8 approaches aren't mutually exclusive, so you can  
9 potentially combine them. This is the Continental  
10 Controls concept -- in the interest of time, I know we're  
11 kind of stressed here, I'm not going to go through it all,  
12 but it's pretty much what I said a minute ago -- off to  
13 the left are pictures of their electronic gas carburetors,  
14 their controller and software is at the top right, and the  
15 NO<sub>x</sub> sensor is pictured at bottom right.

16           This is a schematic of the Continental Controls  
17 System and you can see that the NO<sub>x</sub> sensor is at the outlet  
18 of the exhaust and here it's called a Lambda sensor, but  
19 it's really an oxygen sensor, same one that is used --  
20 similar to the one that is used in the automotive industry  
21 at the front end, and traditionally it's that Lambda  
22 sensor, oxygen sensor that controls the air fuel ratio  
23 controller. The problem is that the Lambda sensor, oxygen  
24 sensors tend to drift and so you may be getting good  
25 emissions one day, you know, the next month there has been

1 some drifting and you're out of compliance. So the NO<sub>x</sub>  
2 sensor actually provides feedback to keep the upstream  
3 oxygen sensor tuned at the exact appropriate level. Here  
4 is some data, you can see this red line here is the NO<sub>x</sub>  
5 limit, the CARB CO limit is up here, nobody really  
6 requires that right now, and the South Coast CO limit is  
7 up there. You can see there's a few excursions; in the  
8 way of excuses, I guess, this is an atypical CHP  
9 application, it's a 300 KW engine that operates at loads  
10 between about 10 percent load, or less than 10 percent  
11 load, up to maybe 40 percent load, and at the very low  
12 load levels, the exhaust temperature isn't hot enough to  
13 fully activate the catalyst, so that's what accounts for  
14 some of the excursions. But it's an older system, so the  
15 permit is way off the charts, so none of these things make  
16 them in any way, shape, or form in violation of their  
17 permit, but it gave us a better understanding as to what's  
18 doable and what's not doable. And I think what we know  
19 now is that, for typical CHP applications where you  
20 operate them close to full all the time, it's going to  
21 perform very well.

22           The Tecogen system, switching projects, again,  
23 they're the ones that widen the air fuel ratio window,  
24 their concept is a dual stage catalyst and where they use  
25 the first stage, which is your typical three-way catalyst,

1 to get the NO<sub>x</sub> down to very very low levels without really  
2 regard to how much CO that you're producing, there is some  
3 upper limits to it, and then with proper conditioning, and  
4 the conditioning has to do with lowering the exhaust  
5 temperature before the second stage, and adding some air.  
6 So you put air injection and, then, in the Tecogen system  
7 which Bill Martini showed, 100 KW, it's a little aquarium  
8 pump is all you need to get the air in there; and to  
9 reduce the heat in a combined heat power system, you're  
10 doing that anyway, so it really doesn't require any kind  
11 of an ancillary cooling system to be added.

12               So that's it in a nutshell and this may be a  
13 little bit hard to follow without me pointing to it, but  
14 this was tested by a third party down in Lake Forest by an  
15 engine R&D house, AVL, and that first -- that short  
16 horizontal arrow shows what the window of control needed  
17 to be without air injection, and the wider band just shows  
18 what it is now for the system with air injection. And  
19 this is 10 months of fuel test data at one of their sites  
20 that have been operating for several years up in San  
21 Fernando, California. That just shows -- so the new  
22 emission system was retrofitted in. This shows 10 months  
23 worth of data, and you can see how low and how well this  
24 thing performed. The South Coast CO limit's way up here,  
25 the CO's almost zero, NO<sub>x</sub> is almost zero. So it's really

1     turned out to be a phenomenal technology, we feel.

2             The Continental Controls and Tecogen are both  
3     proceeding with commercialization. Tecogen is already  
4     integrated into their larger co-gen module, they're  
5     integrating it into all of their other product lines,  
6     which include smaller co-gen systems, engine chillers, and  
7     an engine-driven heat pump.

8             Continental Controls is starting to pursue the  
9     retrofit market right now, a lot of people that have  
10    engines that are having trouble, mostly in the South Coast  
11    Air Quality Management District, and keeping their engines  
12    in tune on a continuous basis, and they're all looking at  
13    expanding the market with dealers and the engine OEM  
14    manufacturers and, in the case of Continental Controls and  
15    with Tecogen, I think they're also looking at making this  
16    technology available to others outside of people that just  
17    have their products.

18            So that, in summary, both of these technologies  
19    are a fairly low cost incremental item, yet enables the  
20    least cost CHP technology which is engines, less than five  
21    MW in size, to remain a viable option in California. It  
22    makes available technologies that enable continuous  
23    compliance with the permit limits and we think it will  
24    create a new clean environmental image for engines. Thank  
25    you.

1           MR. ALDAS: Thank you, Keith. The next topic  
2 will be on the Homogenous Charge Combustion Technology, or  
3 HCCT for CHP Applications. That will be Brandon from  
4 Makel Engineering.

5           MR. BLIZMAN: Hi, my name is Brandon Blizman  
6 with a company called Makel Engineering, a small research  
7 company in Northern California. The reason I'm here today  
8 is to kind of give you guys a little insight as to where  
9 some of your research money from PIER is going. We've  
10 been funded by PIER to do a research project in the  
11 development of Low NO<sub>x</sub> Technology. Now, being an engineer,  
12 I really like where today I've been seeing lots of  
13 acronyms and I can tell that the CHP community likes  
14 acronyms, as well. Here's one acronym I hope you guys  
15 walk away from today's meeting with, it's called HCCI.  
16 Well, what is HCCI? It stands for Homogenous Charge  
17 Compression Ignition. It's an engine emission cycle that  
18 kind of -- it's a hybrid, if you will, of compression  
19 ignition and spark ignite concepts. What it does is  
20 allows the low energy content fuels like biogas to combust  
21 at a high efficient low emissions method.

22           So why would we be doing HCCI for CHP  
23 applications? Well, first of all, it's highly efficient,  
24 upwards of 80 percent efficiency -- I'm not going to go  
25 into the details of that, but it's obviously going to



1 reduce electricity cost for CHP owners, displace the need  
2 for fossil fuels. The other benefit, obviously, is the  
3 low emissions. Without any NOx after treatment, we're able  
4 to see lower, I guess, on the low end of 3 ppm, obviously  
5 it reduces air pollutants. Fuel flexibility, HCCI has  
6 around the world been demonstrated on a variety of fuels.  
7 Makel Engineering successfully has demonstrated on  
8 landfill gas and we're looking forward to demonstrating on  
9 digester gas, low cost, the CHP system is looking at cost  
10 of around \$1,200 KW to install.

11           Some of the technical challenges that we see for  
12 the development of this technology is biogas operation and  
13 biogas situation; the Btu content can vary almost  
14 sometimes on an hourly basis, depending on the  
15 composition. That's where Makel Engineering and our  
16 research partners in Berkeley have been able to bring our  
17 expertise to develop a control system to maintain HCCI  
18 combustion.

19           Heat transfer components -- some of the  
20 conventional heat transfer components, you aren't able to  
21 use those on an HCCI combustion cycle because the exhaust  
22 gas is a little bit cooler than on a typical reciprocating  
23 engine. Now, continuous operation, as with any other CHP  
24 application, you know, variable thermal and electrical  
25 loading requires some active control systems.

1           To control HCCI, specifically for biogas, active  
2 thermal conditioning of the air fuel charge, it's the lean  
3 combustion, you know, we're talking air fuel ratios  
4 anywhere from 50, to 60, to 1. So that intake charge gets  
5 heated, regulated, and auto ignition takes place. Now,  
6 this is the complex function of the engine geometry.  
7 Again, there's an active control system. If that intake  
8 charge gets too hot, it's going to pre-detonate, if it's  
9 not quite hot enough, it's not going to fire at all. So  
10 why would Makel Engineering be looking at this as a  
11 marketable product? Well, we really think that  
12 renewables, in general, and biogas specifically has a very  
13 significant opportunity for us to develop this technology  
14 and deploy this technology. We think there's about a 760  
15 MW of biogas available and our potential for 160 MW of  
16 biogas from dairies available in California;  
17 unfortunately, we're talking about potentials here, we're  
18 not talking about currently installed. From a biomass  
19 standpoint, all the other biomass types of facilities --  
20 capacities -- that totals around 180 MW. So you can see  
21 why we're trying to go after kind of the larger market  
22 focus. That's not to discount the other applications for  
23 CHP, HCCI, light industrial applications such as food  
24 processing plants, hospitals. A lot of the challenges  
25 there are because of the site infrastructure, you know, is

1    there a high electrical load?  Is there a thermal load?  
2    It kind of depends on the site-specific.  You know, the  
3    systems that Makel Engineering has developed, we've kind  
4    of got three systems that we've been working with U.C.  
5    Berkeley on, and the first one is the landfill gas system.  
6    We successfully demonstrated a 30 KW system at a landfill  
7    and we were able to generate kind of to verify what the  
8    labs have been generating, kind of an efficiency NO<sub>x</sub>  
9    profile, and I'll show that here in just a minute.

10           The second system we're developing, it's  
11    currently under development, is not a CHP system, it's  
12    just for straight distributor generation, this is kind of  
13    a scale-up of that technology we developed at the  
14    landfill, you know, characteristics are that it's about 35  
15    percent efficient, it's hopefully going to be certifiable  
16    after our demonstration period, and it's got a standard  
17    grid interconnection.

18           The third system we are developing is a CHP  
19    system, this is kind of a -- let's just say a sweetener  
20    for the landfill gas system, we're going to try to make  
21    that system a little more efficient.  We anticipate around  
22    80 percent CHP efficiency.

23           Here's a little bit of details about our  
24    landfill gas system.  We developed a prototype, again,  
25    working in conjunction with U.C. Berkeley researchers.  We

1 demonstrated a landfill in Butte County, California, it  
2 saw about 500 hours of landfill gas, and we were able to  
3 generate this curve you see down here on the right, it's  
4 an efficiency vs. emissions curve, and that was kind of  
5 the profile we used to move forward with this technology.  
6 This next system here, we're developing with some PIER  
7 funding. This is to scale up the technology and you see  
8 the picture there, it's kind of our concept of the system,  
9 it's going to hopefully be capable of around 100 KW. It's  
10 going to have that same emissions and efficiency profile.  
11 It's basically a stock diesel engine block with an  
12 advanced control system on it and some thermal  
13 conditioning.

14 Our CHP system, now, you can see kind of a  
15 system schematic there, I'm not going to get too much into  
16 the details here in the interest of time, but using a  
17 closed loop recovery system, we think we're going to see  
18 efficiencies in the 80 to 90 percent range.

19 Now, operating on simulated biogas at our  
20 testing facility indicates that we've seen some pretty  
21 significant reasons why we would want to advance this  
22 technology, 80 percent efficiency. Now, we're working in  
23 conjunction with SMUD. This is one of the things that we  
24 learned in our previous project, is in developing these  
25 kind of projects to get your interconnect dealt with, you

1 want to bring some of your utility partners on your team.  
2 It happens to maybe streamline the process. Our first  
3 demonstration site for this 100 KW system is going to be  
4 at the Tollenaar Holsteins Dairy in the next few months  
5 here. They currently have a system, a digester installed,  
6 and they're producing about 150 KW. The CHP application  
7 there is for thermal management of the digester and hot  
8 water for the wash down.

9 Our other CHP system, the smaller system, is  
10 going to be installed early next year in Galt, California  
11 at the Cal-Denier Dairy. Their application for CHP is to  
12 have hot water at onsite laundry facilities.

13 I'd like to kind of wrap things up there and I'm  
14 open to any questions, and here is my contact info for the  
15 future.

16 CHAIRMAN WEISENMILLER: Thanks very much to all  
17 the panel for the presentation. Any questions from the  
18 audience? Again, thanks for organizing this, this is  
19 pretty interesting.

20 MR. ALDAS: Thank you very much. If there are  
21 no questions, I will be calling on David Vidaver for the  
22 next panel.

23 MR. VIDAVER: Good afternoon, Chairman, ladies  
24 and gentlemen. I'll get on the right slide here. My name  
25 is David Vidaver. I work for the Energy Commission's

1 Electricity Analysis Office. I work primarily on long  
2 term planning issues and I probably know less about CHP  
3 than anybody in this room, so this is going to be a very  
4 brief presentation of about six slides, and then we can  
5 get to people who can provide you with some valuable  
6 information.

7           The loading order includes Combined Heat and  
8 Power. We see the two targets that are bandied about  
9 quite frequently, 6,500 megawatts by 2030, and the  
10 Governor's Clean Energy Jobs Plan, and the 4,000  
11 megawatts/6.7 million metric tons by 2020 in the AB 32  
12 Scoping Plan issued by the ARB, and updates to that plan  
13 no longer mention a megawatt target, the target specified  
14 in terms of GHG emissions reductions, but the 6.7 million  
15 metric tons has made its way into other forums.

16           The ARB targets, both megawatts and GHG  
17 reductions, found their way into the CPUC's 2010 Long Term  
18 Procurement Proceeding. The standardized planning  
19 assumptions used in that proceeding included the continued  
20 operation of existing CHP plus the IOU share of 50 percent  
21 of the ARB megawatt target, with outputs split 50-50  
22 between onsite generation and export, in keeping with  
23 ARB's Scoping Plan assumptions.

24           The megawatt numbers that are presented in this  
25 slide are actually net energy for load, not assumed CHP

1 capacity, which is a bit smaller, as a share of CHP output  
2 would be consumed onsite, obviating the need for slightly  
3 more central station capacity due to transmission losses.

4 A review of public utility filings in the 2011  
5 IEPR and Integrated Resource Plans that they have made  
6 available indicate that public utilities as a rule do not  
7 explicitly plan to meet future needs with new CHP. I will  
8 not offer an explanation for this, I assume by merely  
9 pointing these facts out we might hear from the POU  
10 community in oral or written comments. This is  
11 significant as targets and planning assumptions adopted by  
12 the CPUC for entities under their jurisdiction, based on  
13 the ARB Scoping Plan, logically assume that POUs will  
14 contribute towards meeting statewide targets, and as Mr.  
15 Darrow pointed out this morning, roughly one-quarter of  
16 the CHP potential in the Base Case he models will come  
17 from LADWP, SMUD, and "other."

18 The set aside of roughly 1,500 megawatts for CHP  
19 through 2020 in the 2010 Long Term Procurement Proceeding  
20 may seem somewhat innocuous, given California's current  
21 capacity surplus and the expectation that large amounts of  
22 renewable capacity can be expected to be developed during  
23 the remainder of the decade. But, as we all know, more  
24 than 12,000 megawatts of gas-fired generation is expected  
25 to be retired by 2020 in order to comply with the State

1 Water Resource Control Board's policy on once-through  
2 cooling. Decisions regarding the development of resources  
3 lowest on the loading order, conventional gas-fired  
4 generation, will likely be made as part of the CPU's 2012  
5 Long Term Procurement Proceeding, in other words, perhaps  
6 as soon as the end of this year. This is necessary due to  
7 the time needed to contract with, permit, and construct  
8 the new gas-fired generation needed for local reliability  
9 and to integrate intermittent renewable resources.

10           While the amount of capacity needed remains to be  
11 determined, parties generally agree that such capacity  
12 will need to be flexible, quick starting, fast ramping,  
13 and able to operate over a wide range of output. The  
14 amount of capacity authorized will depend in part on  
15 planning assumptions regarding preferred energy resources.  
16 Energy efficiency, both committed and uncommitted, demand  
17 response, renewable resources and, of course, combined  
18 heat and power.

19           Parties have focused and are focusing on the  
20 capacity value of renewable resources and the California  
21 ISO's stakeholder process on the integration of renewable  
22 resources into the electricity system. Assumptions  
23 regarding other preferred resources in the Long Term  
24 Procurement Planning process have perhaps received less  
25 scrutiny to date and are such that California ISO cautions



1 prudence in planning that these resources will be  
2 available in the amounts assumed.

3 In sum, failure to realize CHP development in  
4 the next two to three years may result in additional gas-  
5 fired generation to meet local capacity requirements and  
6 integration needs, or delayed retirement of once-through  
7 cooled facilities.

8 These are the existing programs devoted to CHP,  
9 one could logically contend that, as currently  
10 constituted, they cannot be relied upon to meet a lion's  
11 share of a, for example, success in 500 MW target over the  
12 next 12 years. This isn't to say that we couldn't see a  
13 large amount of CHP developed through other mechanisms,  
14 including pure economics. The *Spark Spreads* were  
15 anticipating -- encourage new development of CHP, the  
16 obstacles to that development pointed out here today,  
17 notwithstanding.

18 The perhaps most significant variable which  
19 affects CHP going forward is the impact of the QF  
20 Settlement. The settlement requires the investor-owned  
21 utilities to develop 3,000 MW of new CHP contracts, but it  
22 should be noted that existing CHP contributes to this  
23 goal, and there is a companion target of 4.3 million  
24 metric tons of greenhouse gas emissions, the CPUC  
25 jurisdictional share of the ARB target. But, least

1 cost/best fit criteria may be used by the utilities to  
2 justify failing reaching those targets, and the  
3 incremental contributions of CHP to meeting the GHG  
4 reduction target on a metric ton per megawatt basis could  
5 be somewhat small.

6           So the presentation by Jen Kalafut of the  
7 California Public Utilities Commission, which is going to  
8 follow me, and the panel discussion, which is going to  
9 follow that, is largely going to focus on these questions:  
10 what are the possible impacts of the QF Settlement on the  
11 development of new CHP in California? So I'll stop  
12 wasting your time and introduce Jennifer, whose office at  
13 the CPUC -- well, I'm not exactly sure what you did, but I  
14 know she knows far more about the QF Settlement than I do  
15 and has done far more analysis with access to far more  
16 data than I have. So, thank you. Any questions?

17           MS. KALAFUT: Okay, thank you and thanks for the  
18 intro, David. I'm not too sure what I do either, so....  
19 And I did want to address a question that came up earlier  
20 regarding the SGIP Program. I heard from my colleagues at  
21 the PUC that all bottoming cycle is meant to be eligible  
22 for SGIP, it was not just a Rankine Cycle. I think  
23 Barbara brought that up before.

24           So I am going to go through some of these slides  
25 rather quickly, there are quite a few here, and I know

1   that we're limited on time, but will say a few brief words  
2   about tracking CHP capacity and GHG emissions, talk a  
3   little bit about some of the key concepts of understanding  
4   GHG analysis of CHP, and then really get into the QF CHP  
5   Settlement and GHG accounting underneath that, and a few  
6   sort of simplified scenarios that CEC was interested in  
7   seeing.

8               So we heard from ICF this morning on their work  
9   on tracking CHP in the state so far, and I think that  
10   they've done a really great job on this. Estimates on  
11   existing CHP capacity in California to date can vary  
12   widely. A lot of this has to do with difficulties in  
13   estimating how much CHP is consumed onsite for some  
14   facilities, for CHP exporting to the grid; while there is  
15   public data available for Qualifying Facilities (QFs),  
16   there's no public data available on non-QFs.

17              As ICF also mentioned, we had a lot of lack of  
18   common data points among CHP databases, including CEC,  
19   CPUC, and the California ISO. And historically there's  
20   been a lack of a common definition of "capacity" which has  
21   made it hard to track well. But, as I said, CEC and ICF  
22   have really further narrowed this gap through a project-  
23   by-project analysis. And the good news is there's better  
24   data collection coming, both with the ARB cap and trade  
25   regulation and the CPUC reporting requirements for IOU

1 procurement under the new QF/CHP Program.

2           The CPUC did do some Data Collection in 2009 and  
3 2010, which returned around 67,000 [sic] MW of operational  
4 CHP in the IOU's territories, so this data is a couple  
5 years old at this point and it has changed a bit. I will  
6 just say that I think the conclusions are largely  
7 consistent with what the ICF has found and that most of  
8 the CHP is in QFs, and sort of the vast majority of CHP  
9 capacity is in larger projects.

10           So tracking GHG emissions from CHP. This can  
11 also be challenging because CHP, as we know, has a wide  
12 range in operational profiles. It can range anywhere from  
13 100 kW to -- I think the biggest system we have in the  
14 state is 300 MW, or maybe even larger. Capacity factors  
15 can run anywhere from 10 to 95 percent. There's a lot of  
16 variance in how much power to heat a particular CHP  
17 facility will be producing, and also a lot of variance in  
18 the ratio between what is being exported and what is being  
19 consumed onsite.

20           Measuring efficiency in a CHP unit is also  
21 unique because you have to look at both the electrical and  
22 the thermal efficiency. And these efficiencies often have  
23 an inverse relationship. If you're generating electricity  
24 at a very low efficiency, you're producing more waste  
25 heat, which drives up the ability for waste heat to

1 capture, and then obviously your thermal efficiency.

2           Finally, there's some more study that is needed  
3 to be done on what CHP is avoiding in terms of the  
4 efficiency or the emissions factor of the grid and the  
5 efficiency of standalone boilers.

6           So this is just a formulaic sort of explanation  
7 of what I just said. Total efficiency is a straight sort  
8 of the electrical efficiency plus thermal efficiency. The  
9 power to heat ratio, as I mentioned, looks at how much  
10 electrical output over the thermal output, and then sort  
11 of a key factor in understanding the GHG analysis of CHP  
12 is what's often referred to as a double-benchmark. And  
13 this simply means that, when comparing CHP against  
14 separate heat and power, two avoided emission factors are  
15 needed, what would CHP -- if not for the CHP facility,  
16 what would the facility be using in terms of a standalone  
17 boiler, and what is it avoiding in terms of the grid  
18 efficiency?

19           One way to think about this double benchmark is  
20 to look at this curve and, for those of you who haven't  
21 seen this curve before, a simple way of looking at this is  
22 for CHP operating towards the left-hand side of this  
23 graph, so with a very low power to heat ratio, and so  
24 therefore producing more thermal than power, that facility  
25 is competing against the efficiency of a standalone

1 boiler. So the efficiency is increasingly, in order to be  
2 net GHG beneficial, it increasingly has to be more towards  
3 the 80 percent range, where a CHP facility operating more  
4 towards the right-hand side of the graph is operating more  
5 like a generator and has to compete against the efficiency  
6 of the grid.

7           You know, just to say quickly about some  
8 assumptions regarding CHP, the ARB Scoping Plan used a  
9 avoided grid emissions of around 437 kg of CO<sub>2</sub> per MWh, and  
10 this is based on a weighted average statewide emissions  
11 from gas-fired generation in 2002 to 2004; and as we sort  
12 of look towards the future, it may be worth considering  
13 what the potential avoided grid emissions would be in  
14 2020. As we know, our grid is getting cleaner, and if we  
15 think about what the load growth in natural gas generation  
16 will be, we could envision a mix of new combined cycle gas  
17 turbines mostly, and then some new combustion turbines,  
18 which typically act as our peakers, which would produce a  
19 avoided grid emissions closer to around a 7,100 heat rate.

20           If we look at this, the impact that this has on  
21 sort of emission reductions from CHP is, as the grid gets  
22 cleaner, we move from that blue line up to that yellow  
23 line, and so, as we go forward in the future and as the  
24 grid potentially gets cleaner, it becomes harder and  
25 harder for CHP to compete from a GHG perspective. And I'm

1 moving through this rather quickly, so let me know if you  
2 have any questions.

3 Just moving on to the QF/CHP Settlement. In  
4 November of last year, a global settlement was reached  
5 between CHP representatives and the IOUs, along with  
6 ratepayer advocacy groups, that put in place a new CHP  
7 program through 2020. There are a number of components to  
8 this settlement and I've listed here some of the key  
9 provisions, but what is most relevant to this discussion  
10 is the megawatt procurement and GHG reduction targets for  
11 IOUs, for the IOUs.

12 As David already mentioned, under the QF/CHP  
13 Settlement, the IOUs have a megawatt procurement target of  
14 3,000 MW by October of 2015, it may be November 2015, but  
15 by the end of 2015. And this can be a mix of new or  
16 existing CHP. And then the IOU GHG reduction target is an  
17 incremental 4.3 MMT CO2 by 2020. And as David already  
18 said, this is based on the IOU's share of the ARB Climate  
19 Change Scoping Plan CHP target.

20 MW and GHG accounting towards the targets are  
21 very specific to the Settlement. This takes into account  
22 that no two CHP facilities are alike and the accounting  
23 really reflects these differences.

24 Some of the rules for GHG Accounting under the QF/CHP  
25 Settlement include an avoided emissions calculated using

1 the "Double Benchmark" and the Settlement defines the  
2 Double Benchmark at an 8,300 heat rate and an Avoided  
3 Boiler Efficiency of 80 percent. The settlement does not  
4 contemplate different avoided emission factors for export  
5 CHP or for CHP that's being used onsite.

6           Some nuances in the accounting for the QF/CHP  
7 settlement for the GHG target is, if the IOUs have a "must  
8 take" procurement, so under the PURPA Program, for  
9 example, they have to sign up a particular CHP facility  
10 and that facility is net GHG emitting. It will not count  
11 -- this is not worded correctly, but it will not count as  
12 a debit in the GHG target. So, if the IOUs have to take  
13 on a particular type of procurement that is not GHG  
14 beneficial, it's not going to count against them in  
15 reaching their GHG goals.

16           Another nuance is for terminated and shut-down  
17 facilities, the energy, and therefore the GHG emissions,  
18 are replaced at a defined market heat rate. So the  
19 Settlement envisioned that, if something shut down, those  
20 megawatts can't just disappear, but they're being replaced  
21 by something, and that sort of factors into the GHG  
22 accounting, as well.

23           And finally, utility-owned generation can only  
24 account up to 10 percent of the IOUs' GHG target.

25           In running some of the scenarios that CEC asked



1 for, we used the data that we collected in 2009 and 2010.  
2 From that data, we did have some specific performance  
3 information for about two-thirds of the CHP IOU fleet, or  
4 about 4,500 MW. And if we wanted to just take a snapshot  
5 of what this 4,500 MW is producing or avoiding in terms of  
6 GHG, using the QF/CHP Settlement assumptions, and that's  
7 the 8,300 Heat Rate, and an avoided boiler efficiency of  
8 80 percent, of the 4,500 MW is net emission reducing of  
9 about 2.16 million metric tons. That's sort of just a  
10 snapshot of the fleet as it is.

11           However, and this sort of gets back to my slide  
12 on the assumptions previously that I sort of rushed  
13 through, but if we make different assumptions about what  
14 CHP is displacing, we can see sort of dramatically  
15 different net emission reductions from the existing fleet.  
16 So if we think about emission factors that reflect a  
17 cleaner load growth in terms our gas-fired generation, and  
18 a varying avoided emission for CHP that is consumed  
19 onsite, the same set of CHP generators at 4,500 MW all of  
20 a sudden is not as clean under these different  
21 assumptions. So that's just to illustrate the impact that  
22 these assumptions can have on the GHG analysis that we do.

23           So getting on to the scenarios that we ran, we  
24 wanted to look specifically at what was expiring before  
25 2020, since this is the most relevant set of generators.

1 And again, these scenarios are meant to be illustrative  
2 and I'll talk a little bit more about this, but updated  
3 data is needed for accurate planning purposes.

4           So the three scenarios that we looked at were,  
5 first, if we retired all of the net emitting facilities  
6 above 20 MW, if we just said that 800 MW or so is net  
7 emitting, it's not going to be resigned, and it just goes  
8 away, what kind of net emission reductions would we get?  
9 If we re-contracted all the net reducing facilities, or  
10 let 2,500 MW, what kind of emission reductions would we  
11 get? And if we repowered some of these facilities, how  
12 much closer would the utilities get to their GHG goals  
13 under the QF Settlement? And this is just the breakeven  
14 curve with the net reducing facilities above the curve,  
15 and the net emitting facilities below it.

16           So under the QF/CHP Settlement, if a facility is  
17 completely retired, and this is if the CHP facility  
18 completely shuts down, and no thermal need continues, how  
19 the GHG accounting is envisioned under the settlement is  
20 that it actually does not use the double benchmark, but it  
21 takes the baseline emissions of the facility and subtracts  
22 out how that power would need to be replaced at a  
23 particular replacement energy heat rate that is defined in  
24 the Settlement. So, if we looked at these 800 MW of net  
25 emitting facilities that I showed before, and completely

1 shut them down, no thermal need continues, and included in  
2 there the emissions from the replacement energy, we could  
3 get about a .78 million metric tons of reductions from the  
4 -- as the IOUs could sort of count that towards their GHG  
5 reduction goal.

6           The second scenario that we talked about was re-  
7 contracting all net reducing facilities. So under this  
8 scenario, we would use the double benchmark as defined in  
9 the settlement, an 8,300 heat rate and an 80 percent  
10 efficient boiler, and the calculation is simply by taking  
11 the avoided emissions from separate heat and power minus  
12 the CHP emissions. So what we've already talked about  
13 before, really. What is a CHP producing in terms of  
14 emissions, and what is it avoiding if those CHP facilities  
15 used separate heat and power, and the difference is the  
16 net emission reductions, and we can see a significant  
17 amount of net emission reductions from re-contracting on  
18 net reducing facilities.

19           And finally, if we wanted to look at repowering  
20 some of the least efficient facilities, so even though a  
21 facility may be net emission reducing, it could have a  
22 total efficiency of below 60 percent or below 62 percent.  
23 If we wanted to say, okay, as a scenario, all those  
24 facilities brought their operations up to a 62 percent  
25 total efficiency, the way that the settlement would look

1 at this is to use a double benchmark, look at the avoided  
2 emissions of the repowered facility, so what is a facility  
3 avoiding after it has been repowered and take out what the  
4 facility was avoiding prior to the repower, in order to  
5 get the net emission reductions. And again, we can see  
6 some significant net emission reductions from that.

7           So I just wanted to say that these scenarios,  
8 again, are not comprehensive of all the different things  
9 that could happen under the QF/CHP Settlement with the  
10 existing fleet. There's many different procurement  
11 options for existing CHP and there could be some  
12 combination of these three, they're not mutually  
13 exclusive; these megawatts could go on a lot of different  
14 pathways. And I think that a more detailed analysis is  
15 necessary to determine on a project-by-project basis the  
16 most likely procurement pathway that a particular CHP  
17 facility would take under the QF Settlement in order to  
18 determine what type of -- or in order to plan for what  
19 type of emission reductions we would get.

20           So just in conclusion, the potential to achieve  
21 -- there's a high potential to achieve significant  
22 emission reductions from the existing CHP fleet. And I  
23 think that this is really important as we think about  
24 targets for CHP going forward because there's a lot of  
25 benefit to looking at our fleet as it is right now, our

1 CHP fleet as it is now, and thinking about how could it be  
2 cleaner, how could we get more emission reductions from  
3 what we already have? But these emission reductions  
4 depend greatly on the assumptions that we make about what  
5 CHP is avoiding, both in terms of what is it avoiding in  
6 terms of grid emissions, and what is it avoiding in terms  
7 of industrial boilers. So, in turn, the potential  
8 procurement of new generation to help meet GHG targets  
9 under the settlement depends on how the existing fleet is  
10 performing. Clearly, the more GHG reductions we receive  
11 from the existing fleet, the more limited space there is  
12 for new generation to contribute to GHG targets.

13 I do want to say that the QF/CHP Settlement  
14 Reporting Model, where a lot of these calculations --  
15 where all of these calculations are done, will be publicly  
16 available. So the model template will be available on our  
17 website for interested stakeholders to run both GHG  
18 emission reductions and megawatt procurement scenarios.  
19 And the first completed IOU reports are due at the end of  
20 March 2012, and they will be publicly posted on the CPUC  
21 website in April. And then this happens semi-annually on  
22 a six-month basis.

23 Also, competitive -- it's important to keep in  
24 mind that competitive solicitation under the settlement is  
25 just one of many CHP procurement programs that we have in

1 the state right now, including what is under the  
2 settlement. There continues to be the less than 20 MW  
3 PURPA program, which is one of the sort of "must take"  
4 procurement programs, in addition to the CHP Feed in  
5 Tariff Program, which we've heard a lot about today.  
6 Under the settlement, there are options of other programs,  
7 including an as available program, which is for large  
8 facilities making large facilities above 20 MW, but making  
9 very small energy deliveries. There is a program for  
10 facilities that are called Utility Pre-Scheduled  
11 Facilities, and these are facilities that have some  
12 dispatchability options, so if you're a large facility and  
13 you can be dispatchable, this is another option for you,  
14 and then, of course, there's the SGIP Program, which we've  
15 already talked about.

16 And lastly, I wanted to say that we focused a  
17 lot on GHG reductions in this presentation, but CHP can  
18 have many other benefits besides GHG reductions, which  
19 panelists have talked about previously throughout the day.  
20 There are benefits for grid reliability, relieving grid  
21 congestion, onsite energy sources for the host facilities,  
22 bottoming cycle CHP has a lot of benefits, biomass and  
23 biogas and other renewable fired CHP has a lot of  
24 benefits, as well.

25 So as we were thinking about targets for CHP, I

1 think it's important to think about what the specific  
2 goals are that we're trying to achieve with CHP and really  
3 make those targets fit with the goals that we're trying to  
4 reach. That is the end of my presentation.

5 CHAIRMAN WEISENMILLER: Yeah, thanks for the  
6 presentation. I was going to say, certainly, again, I  
7 would like to congratulate the PUC, the utilities and the  
8 co-generators for reaching this settlement. I mean, one of  
9 the things we've learned over the decades is you cannot  
10 walk into a utility control room with the ISO and see what  
11 the heat rate is at that moment, it's something that  
12 everyone calculates, the utilities tend to calculate very  
13 low values, they tend to look at system Lambdas, they tend  
14 to avoid -- to ignore startup and their load fuel, and the  
15 co-generators tend to try to find the most inefficient  
16 plants and use that as the benchmark. Presumably this  
17 number is somewhere in between and hopefully the arguments  
18 are over, so we don't want to hear the utilities saying,  
19 "Well, gee, this number is too high" because I'm sure that  
20 would then provoke every caller to say "it's too low." So  
21 it's a settlement, we'll move forward, it's probably good  
22 enough for what we need to do. But, anyway, again, I  
23 personally was fairly skeptical for a long time that a  
24 settlement would occur, but bless you, it did. And as you  
25 said, the purpose of this is really to get to greenhouse

1 gas -- you know, we're looking at greenhouse gas  
2 emissions. I would say the double -- we sort of bounced  
3 that idea here, the double test because, I mean, people  
4 for decades have been looking at the total fuel going in,  
5 looking at that netting out thermal use, and coming up  
6 with an effective heat rate for power. And that benchmark  
7 gives you a pretty good easy thing to say, okay, if it's  
8 5,000, which if you do that calculation which I've done  
9 for some of the Chevron Refinery projects, it's very  
10 efficient and obviously some of the PURPA machines are  
11 more nine to 10 and they're just not competitive in  
12 today's world. But, anyway, the double benchmark is one  
13 way of looking at it, certainly not the only way to look  
14 at it.

15 MS. KALAFUT: Thank you.

16 CHAIRMAN WEISENMILLER: Again, thanks a lot.  
17 Sure, Tom.

18 MR. CASTEN: Thank you, Tom Casten. Two  
19 questions. First of all, in your calculation of the  
20 greenhouse gas, if the utility were to purchase VAR  
21 support and then, therefore, cut the line losses down, how  
22 would that factor into your calculations? Would that  
23 generate greenhouse gas the way you're looking at it?

24 MS. KALAFUT: So specifically how do line losses  
25 factor into --



1           MR. CASTEN: No. You've got a distributed  
2 generation plant, nobody buys VARs from it, they start  
3 buying VARs from it, the line losses go down by the kind  
4 of numbers that Carnegie Mellon has talked about, who gets  
5 the credit for the GHG reduction?

6           MS. KALAFUT: I believe the utility would get  
7 the credit for that. I mean, but the thing that you have  
8 to think about in terms of what I was just speaking of is  
9 those scenarios are really meant for sort of scorekeeping  
10 towards the GHG targets under the QF/CHP settlement  
11 because the utilities have this 4.3 million metric ton  
12 reduction target under the settlement, there are  
13 accounting rules that help, that have been put in place  
14 and were negotiated during the settlement about how the  
15 utilities will get to that goal. This doesn't have  
16 anything to do with how allowances are going to be  
17 retired, or compliance obligations for the facilities or  
18 the utilities, so we have to keep those concepts separate.

19          MR. CASTEN: Okay. My second question is that  
20 you talked about trying to find the CHP that is not net  
21 beneficial.

22          MS. KALAFUT: Uh huh.

23          MR. CASTEN: But it seems like a binary on or  
24 off. Have you looked at the fact that every CHP plant is  
25 basically a perfectly thermally matched plant up to some

1 point, and then a straight electric generating plant  
2 beyond that? If it's a 91 Btu, a 9,100 Btu heat rate,  
3 it's 5,500 Btus on the thermally matched and 11,000 on the  
4 other part. So the question to me would not be shutting  
5 that plant down --

6 MS. KALAFUT: Uh huh.

7 MR. CASTEN: -- but crafting regulations that  
8 make it less attractive to run the electric only part of  
9 it that's not thermally matched. Is that in your  
10 thinking?

11 MS. KALAFUT: No, I agree. I think that these  
12 were simplified scenarios to demonstrate, you know, how  
13 some of the accounting works under the QF/CHP Settlement  
14 towards these GHG goals. But, yeah, I think there's a lot  
15 of ways, even for an inefficient facility, to stay online  
16 by doing some of the things that you just talked about.

17 MR. CASTEN: Thank you.

18 MS. VAUGHN: Thank you. Beth Vaughn with the  
19 California Cogeneration Council. Hey, Jen, just wanted to  
20 just clarify one thing and just make sure we're both on  
21 the same page, I think we are. But in terms of the  
22 accounting, can you go to Slide 17? Right. So I just  
23 wanted to make sure people understand, and hopefully I'm  
24 understanding this correctly, is in the scenario 2 where  
25 Jen has looked at re-contracting all the net reducing

1 facilities that exist, when we're looking at the goals of  
2 the 6.7 million metric tons and the 4.3, then, for the  
3 utilities, if these existing facilities have no change in  
4 operations, so they're already highly efficient, and the  
5 utility -- they went in the bids with the utilities --  
6 they're going to come across as a zero, they're not going  
7 to be 1.71 million metric tons in terms of counting  
8 towards the goal. The goal, that 4.3 is additional  
9 installed capacity, so it's the new CHP. So, remember, if  
10 there was no change in operations, where you're absolutely  
11 correct with the repower, and they've done something to  
12 become more efficient, then they count. And I'm looking  
13 back at Jerry and Ray just -- just so when people are  
14 looking at these numbers, the 1.71 you've got up there is  
15 part of the base numbers when you did the calculation back  
16 on Slide 12, where you have 2.16 being the total. So just  
17 to clarify for David because I know you're looking at some  
18 of this information going forward.

19 MS. KALAFUT: Yeah, that's a really good point,  
20 Beth, and thanks for bringing that up. In this  
21 calculation that you see on this slide here, that's true,  
22 this should be for new facilities coming on, new efficient  
23 facilities coming on would use this type of calculation.

24 MS. VAUGHN: Against the Double Benchmark,  
25 right.

1 MS. KALAFUT: Okay, that's helpful. Thank you.

2 CHAIRMAN WEISENMILLER: Okay, thanks again.

3 Question? Go ahead.

4 MR. DAVIDSON: Keith Davidson with DE Solutions.

5 Jennifer, a lot of us in the customer side, co-gen  
6 industry have trouble rationalizing the greenhouse gas  
7 benchmark that reduces the wholesale CHP plant benchmark  
8 by the amount of RPS that's in there. And you wind up --  
9 and I kind of understand the logic and the math -- but you  
10 basically wind up distorting or minimizing the value of  
11 onsite greenhouse gas reductions relative to wholesale  
12 greenhouse gas reductions.

13 And it's not just -- it's not just CHP, it's all  
14 customer side of the meter measures that get reduced by  
15 the 20 percent or the 33 percent, and so it would be  
16 renewables on the customer side, it would be energy  
17 efficiency, all of that, the same logic would apply. And  
18 to me, it's a policy consequence that is very troubling  
19 when you start saying that the customer side of the  
20 measures are worth less than wholesale measures. And I  
21 think that's where this thing is leading to, and I just  
22 worry that that's the wrong signal you want to send to the  
23 rest of the State because, you know, the onsite measures,  
24 they've got no T&D, there's so many advantages to onsite  
25 DG and energy efficiency relative to the wholesale

1 measures that, to me, it begs maybe some policy changes  
2 might be in order. But that's just my opinion.

3 MS. KALAFUT: Yeah, but I think that from a GHG  
4 perspective, if we're just looking at this from a GHG  
5 perspective, it is true that onsite CHP may not perform as  
6 well as CHP that's exporting to the grid because CHP  
7 exporting to the grid is only average displacing natural  
8 gas where CHP used onsite is also displacing some  
9 renewables. So it has a lower avoided emissions factor.  
10 But that being said, again, I don't think that we  
11 necessarily need to be looking at CHP and planning for CHP  
12 just from a GHG perspective if we want to consider all the  
13 multiple benefits that CHP could potentially have. And  
14 customer-side CHP lowers the demand forecast and has grid  
15 reliability benefits, and so that's something that should  
16 definitely be taken into account.

17 CHAIRMAN WEISENMILLER: Anymore questions, and  
18 the general comments on policy we're going to hold to the  
19 public comment section. Again, specific questions are  
20 fine.

21 MR. MARTINI: Just wanted to follow-up on what  
22 Keith had said, that 100 KW generator that is using the  
23 power onsite with a certain efficiency is really having  
24 the same effect in the world as one that's exporting 100  
25 KW 100 percent. It seems like it's kind of arbitrary

1 whether you say "these 100 KW displace some renewables and  
2 these 100 KW don't." It's all where you put the meter. I  
3 mean, literally, you put the meter six feet to the right  
4 and suddenly it's exporting, and it seems like the actual  
5 physics of the molecules of CO<sub>2</sub> are the same, either way.  
6 It's all kind of an arbitrary policy assumption. So I  
7 would hate to see onsite measures of all kinds, like Keith  
8 said, penalized. So...

9 CHAIRMAN WEISENMILLER: Next speaker. Thanks.

10 MR. ALCANTAR: I'm part of Jennifer's panel, so  
11 I'm going to --

12 CHAIRMAN WEISENMILLER: I was just going to  
13 encourage you to --

14 MR. ALCANTAR: How would you like to proceed?

15 MR. VIDAVER: Actually, I would like if the  
16 panel members would take seats behind their names at the  
17 table and we're going to post the slide that was sent to  
18 us by the representative from Southern California Edison.  
19 I'd like to take this opportunity to inform the dais that  
20 Public Utilities Commission staff has been incredibly  
21 cooperative, staff in general, and Ms. Kalafut, in  
22 particular, in assisting Energy Commission staff with an  
23 understanding of the settlement and data, etc., so while  
24 we can't actually count in interfering in civil service  
25 processes, maybe you could facilitate a promotion for her,

1 or more vacation, or maybe just buy her a pony? All  
2 right, thank you.

3 We have a distinguished panel of individuals to  
4 talk about what we've just heard and other issues related  
5 to the settlement, and utility procurement of CHP, both  
6 old and new. And we have Michael Alcantar representing --  
7 well, I'll let everyone introduce themselves, so you've  
8 all met Jen Kalafut. Mr. Alcantar, if you could?

9 MR. ALCANTAR: I'm Michael Alcantar. I  
10 represent the Cogeneration Association of California, a  
11 coalition supporting cogenerators (inaudible). Thank you.

12 MR. WILLIAMS: Oh, my name is Ray Williams. I'm  
13 Director of Long Term Energy Policy. I sit in the Energy  
14 Procurement part of PG&E, that's a part of PG&E that buys  
15 electric and natural gas supply for its customers.

16 MR. TORRIBIO: I'm Jerry Torribio with Southern  
17 California Edison. I'm the Manager of Combined Heat and  
18 Power Contracts, which is largely involved with  
19 implementing the CHP Settlement, signing Power Purchase  
20 Contracts and conducting competitive RFO for new and  
21 existing CHP projects. Just maybe a question to the  
22 Moderator. I sent that slide up here and it's not a slide  
23 deck, if that's reassuring, it's a single slide, and I  
24 don't know that the other panelists want to have it up  
25 there or refer to it, but if I may, I'll just say what it

1 is. It's sort of been up here. This is another way, yet  
2 another way, of looking at this issue which has been  
3 raised in various ways in the ICF, it looks like it will  
4 be raised in the ICF Report: can we get there? Can we get  
5 the CARB Scoping Plan reduction? And a couple of the  
6 other presentations have raised the question. And it's  
7 almost complementary to the breakeven curves, I think,  
8 that were in Jennifer Kalafut's presentation. But just  
9 for those that are on the WebEx, I'm pointing these things  
10 out, I hope you can see them, you won't see the laser  
11 pointer, but what we show is three different heat rates  
12 which are the prime movers, there's an 11,000 Btu KWh heat  
13 rate; there's another curve at 10,000 Btu KWh; and there's  
14 finally one at 9,000. And of course, in CHP parlance, we  
15 usually think lower is better, so that 9,000 is a good  
16 one, and the other ones are higher. And what this is  
17 showing on the left axis is totals of megawatts and it's a  
18 calculation using the Double Benchmark of how many  
19 megawatts would be needed to get the statewide GHG  
20 reduction target of 6.7 million metric tons.

21 And the key thing on this is what's on the  
22 horizontal axis, which is the thermal efficiency, the  
23 overall efficiency of the project, which is a measure of  
24 the application. And so, in our portfolio, existing  
25 projects at Edison, we have some that go all the way to



1 the right-hand side, they're up past 75 percent, maybe  
2 higher, and then there are some that are down over toward  
3 the left-hand number, you get down there toward 50  
4 percent, or 45 percent, and you're getting toward the  
5 minimum requirements of the original PURPA rules. And  
6 there is in a red line, a vertical red line, is the  
7 efficiency standard that we set by Assembly Bill 1613 for  
8 the CHP feed in tariff, and the point being that, over  
9 there on the right-hand, the higher efficiency projects --  
10 and when we -- how do we get higher efficiency? As was  
11 described this morning, I think in the Tecogen  
12 presentation, a unit that is intended to run, at least in  
13 the example they gave, all the waste heat is recovered,  
14 it's not dumped, it is not bypassed, and you might say  
15 thermal load following. And then what happens over  
16 towards the left, it may be that the projects are electric  
17 load following more than purely heat following, but the  
18 point is, in the fleet of the future, and what we put  
19 together in our CHP program in California, the higher the  
20 overall efficiency we can achieve collectively with these  
21 projects, the fewer tons would be required to hit the  
22 goal, and obviously you'll notice that the heat rate does  
23 make a difference, but what is really leveraged there is  
24 efficiency. And when the efficiency of the whole project  
25 gets below about 55 percent, they kind of go infinite. So

1 it implies that, unless we work in the design of our  
2 incentive programs, and unless we work in our monitoring  
3 of the CHP Program going forward, and keep track of how  
4 it's working, we could be in a situation where you can't  
5 get there from here. And this is just some noodling to  
6 kind of see what the sensitivities were.

7 CHAIRMAN WEISENMILLER: Okay, again, thank you.  
8 Again, we're not going to get back into the settlement  
9 discussions of what the actual emissions would be, but for  
10 the cogen, but we'll use the settlement number. So  
11 thanks, efficiency is certainly better. But let's move  
12 on.

13 MR. VIDAVER: One of the observations I made  
14 while I was standing at the podium was that the megawatt  
15 targets could be met by resigning existing CHP resources.  
16 Mr. Williams, it's my understanding that PG&E has already  
17 re-contracted with some QFs, procuring capacity that would  
18 be driven to that target?

19 MR. WILLIAMS: So before I answer that question,  
20 I just wanted to get a feel for how we would proceed. Are  
21 Michael and I going to be able to give any opening  
22 remarks? Or are we just here to answer questions?

23 CHAIRMAN WEISENMILLER: Why don't we give  
24 everyone a chance for opening remarks, or both of you a  
25 chance for opening remarks, and then we'll answer

1 questions.

2 MR. WILLIAMS: Michael always wants me to go  
3 first, so I'll go first. Okay, so within the Energy  
4 Procurement part of PG&E, we have a number of goals, first  
5 is reliable supply, second is reasonable cost and  
6 acceptable cost volatility for our customers, sufficient  
7 operating flexibility, obviously, has become more  
8 important as we bring in more renewables. We're looking  
9 to reduce our environmental footprint over time and, of  
10 course, to meet all of our compliance requirements which  
11 include lowering order requirements, RPH, energy  
12 efficiency goals, and now to meet the obligations under  
13 the CHP Settlement.

14 From this, our responsibility, we really need to  
15 take a broad view and look at all of these goals. CHP is  
16 an essentially component of our portfolio, it provides an  
17 aggregate reliable source of firm baseload supply, and  
18 some intermittent supply. The settlement overview itself,  
19 I won't get into too much of that because Jennifer already  
20 did, but it resolved a whole host of litigation. There is  
21 a new State CHP Program, at least as it applies to IOUs,  
22 and there is also a continuation of a PURPA PPA for QFs  
23 under 20 megawatts.

24 I would say we should pat ourselves on the back.  
25 Michael, CAC EPUC, CEC, IEP, DRA, TURN and the three

1 utilities and the PUC, itself, should be commended for  
2 getting together and getting the litigation done and  
3 getting a new procurement structure in place. It  
4 addressed the policy concerns of at least three regulatory  
5 agencies that, in part, is what drives the complexity,  
6 PUC, FERC, and the ARB. I'll try to just hit those items  
7 that weren't hit previously. There's a new short run  
8 energy pricing included. There is a locational adjustment  
9 which at least to some degree reflects where a CHP is  
10 located relative to congestion. It also adjusts for cap  
11 and trade, so when a cap and trade program goes into  
12 place, payments to CHP and QFs will go up to reflect  
13 compliance costs at essentially a market kind of rate, so  
14 we will see that, and that was really a sticking point in  
15 the discussions. So, for export CHP, the parties, you  
16 know, struck an agreement as to how the payments would  
17 adjust as a result of cap and trade. There are five PPAs  
18 and pricing amendments, there is -- as we learned, as the  
19 utility guy learned -- there is CHP that is in all kinds  
20 of different situations, there's some that want to expand,  
21 there's some that want a new contract, there's some that  
22 want to shut down. And so, part of the complexity here is  
23 trying to address the needs of all those various CHP  
24 facilities.

25 Our target is 1387 megawatts by the middle of

1 2015 and, yes, we have signed up for 186 megawatts so far.  
2 And those contracts have been approved by the Public  
3 Utilities Commission, so we're serious, you know, we've  
4 made some commitments here. Actually, the target for the  
5 IOUs, I think, is more like 4.8 and not 4.3, and that is  
6 because we have ESPs and CCAs in our service territory.  
7 They had as part of this settlement the option of either  
8 procuring CHP, or else basically paying the above market  
9 cost of these contracts to the extent that there are any,  
10 they chose the latter, therefore the reductions  
11 themselves, I believe, sort of fall back to the utility  
12 because we will essentially be procuring not only on  
13 behalf of our bundled customers, but on behalf of CCA and  
14 DA customers. You would expect that, because some of this  
15 would reflect long run pricing, there will be some above  
16 market charges and we would look to allocate those not  
17 just to our bundled customers, but to other customers, as  
18 well.

19 We are busy implementing, we've posted short run  
20 energy pricing. We've had increase into various  
21 contracts, it's a complex settlement, and we have a lot of  
22 requirements. The sellers, themselves, have a lot of  
23 requirements. We held a seller's conference to help QFs  
24 and CHP understand what their options and obligations were  
25 under the settlement, and some of them are triggered by

1 the settlement and some are triggered by they sign a new  
2 contract, and now they have to go through an ISO process  
3 for interconnection. And, you know, it's not a short  
4 presentation, but I have a copy of the presentation that  
5 we shared and talked through with the seller.

6 CHAIRMAN WEISENMILLER: That would be great if  
7 we can have that in the record.

8 MR. WILLIAMS: Yes. We also held a CHP RFO  
9 bidders conference, well attended, and took feedback and  
10 posted responses on our website. And we look forward to  
11 receiving bids on the 27th, that's when bids come in for  
12 PG&E, the 27th of this month.

13 For AB 1613, as you know, it's available into  
14 CHP that meets the CEC efficiency requirement. The  
15 pricing is based on all cost of a combined cycle.  
16 Contracts are now available, except, I guess, the one for  
17 small 500 KW is not in effect, there was a Protest filed;  
18 but the other two are now available. CHP, there is an  
19 incentive in place, PG&E did support including CHP in the  
20 SGIP Program, and that will take place, I guess, in 2012.  
21 Overall, and at this point, you have some questions, and  
22 the rest of my comments really go to answering those  
23 questions, so I can stop there and then, presuming you ask  
24 the questions that are on the page, then I can get back to  
25 these other remarks at that point.

1           CHAIRMAN WEISENMILLER: I guess, Ray, the one  
2 question would be, obviously you're in the middle of the  
3 RFO at this stage, but I mean, any indications on how  
4 things are proceeding? Obviously, we'll be looking  
5 forward to hearing after things close, but....

6           MR. WILLIAMS: It's a little sensitive to say  
7 anything right now. I would say that the bidder's  
8 conference seemed quite well attended, but beyond that I  
9 probably shouldn't talk about what we think the response  
10 will be.

11          CHAIRMAN WEISENMILLER: No, that's fine. I was  
12 just going to ask that to the extent they've given us a  
13 similar presentation, or a bidder's conference, if they  
14 could also put that on the record, it would be good, too,  
15 similar to what you've done.

16          MR. TORRIBIO: Yes.

17          CHAIRMAN WEISENMILLER: Michael.

18          MR. WILLIAMS: Oh, actually, I'm sorry, there  
19 was one other thing I wanted to do. I talked with Evelyn  
20 Kahl at the break and I just wanted to clean up my remarks  
21 on EITE, so hopefully I get this right. First is what I  
22 understand is for one sector, oil refineries, updates do  
23 occur, but on a lagged basis, so there can possibly be  
24 recognition of new CHP. Again, it's on a lagged basis, so  
25 it doesn't happen right away, only if under common

1 ownership, but not third party CHP. Okay, and then for  
2 basically the general practice, or for all other sectors,  
3 there is some recognition initially of CHP based on  
4 historical emissions, as long as there is common  
5 ownership, however, for these sectors installing or  
6 expanding onsite CHP is less attractive because historical  
7 emissions do not get updated as a practice at the Air  
8 Resources Board now. So, you know, you would say that, at  
9 least for this group, that this presents a disincentive to  
10 expand onsite CHP because the EITE-based allowance  
11 allocation would not change. Also, it would present a  
12 disincentive if you wanted to go from export to onsite.  
13 So I just wanted to make that quite clear.

14 CHAIRMAN WEISENMILLER: Well, thanks. We should  
15 ask Evie if you've gotten it correct. Yes, okay, thanks.

16 MR. ALCANTER: I was asked by my colleagues to  
17 come up here and make things a little bit more lively, and  
18 I can see that Ray did such a good job that he sent Cliff  
19 home. So I'll have to work a little bit harder.

20 CHAIRMAN WEISENMILLER: Cliff had to take a  
21 call.

22 MR. ALCANTER: But I wanted to try and take a  
23 different tact on what we're talking about a bit, before  
24 we get into some of the numbers and responses to what is  
25 there. And that is that, as a human being we get up every



1 morning and we have hope, we have refreshed hope, no  
2 matter how bad the day was before, we keep hoping. And I  
3 think, Dr. Weisenmiller, you and I have been hoping in  
4 this industry for well over 30 years, and I think we're  
5 still hoping. So today is another day of hope. And I  
6 will say that, from comments from my colleagues, as well,  
7 I'll share with you that I think this is the first  
8 workshop we can remember, in at least our more feeble  
9 memories of late, that has actually been on target, on  
10 issue, with respect to what we really need to deal with.  
11 And some answers that are as blunt as saying, "Tell us, do  
12 you want to send the state CHP or do you want us to shut  
13 down and move out? It's been that bluntly presented. And  
14 I think that's helpful to understand where we're going  
15 next.

16           The other thing, so my second then beyond hope,  
17 is reality. I want to talk a little bit about the reality  
18 of the settlement and what it does and, more importantly,  
19 the illusion of what I keep hearing it does do that I'm  
20 troubled by.

21           And lastly is just the hope that history will be  
22 a predictor of our future. And by history, I don't mean  
23 the history over the last 15 years because that's been a  
24 series of promises not made effective, but the history of  
25 this current Governor in his previous term as Governor,

1 had a halcyon day in terms of development of CHP in the  
2 State. And it was done to solve a very clear problem that  
3 we were facing at the time, how do we get away from  
4 nuclear facilities along our coast? How do we get away  
5 from building coal plants up and down the San Joaquin  
6 Valley? And Distributed Generation was an answer, it  
7 happened to be called QS at that point, but here we are  
8 today again.

9           So let me try to give a different perspective  
10 than I think you're hearing about what the CHP Settlement  
11 does. Ray is exactly right, we were in the woods, and we  
12 had more fights and more litigation and more challenges  
13 sitting in front of us about what we couldn't resolve than  
14 what we could. Those litigations presented real present  
15 risks, retroactive rate adjustments, things that could not  
16 be tolerated, they would render bankrupt many of the  
17 facilities that even I'm operating or dealing with. They  
18 had to be resolved. So we dealt with the past. The  
19 settlement clearly deals with the past. It then said,  
20 "Well, what about these facilities that we're about ready  
21 to lose, that for the last, well, since 2002, 2003, we've  
22 been pounding the table saying there's no State policy,  
23 we're running out of contract time, what are we going to  
24 do next?" And some band aids were applied by the  
25 Commission at that point in time.

1           But in 2004, there was the establishment of --  
2 and you'll like this name -- the QF Long Term Contract  
3 Policy Proceeding. That was just closed by agreement in  
4 the settlement this last time, but we've spent since 2004  
5 trying to figure out if we have a Long Term QF Contract  
6 Policy. What we have and what was settled was a contract  
7 policy that, for existing projects that either have  
8 expired contracts, or expiring projects, which is from  
9 Jennifer's numbers, which I agree with, about 3,151  
10 rounded up or down.

11           We set a figure, negotiated a figure, not all  
12 that proud of, that said, well, we'll procure, we'll  
13 require, if you will, the procurement of 3,000 megawatts  
14 so that at least we're staying static, right? We're  
15 treading water with respect to existing CHP capacity. It  
16 may be some other project that comes in and replaces, that  
17 is more efficient or otherwise, but really what we're  
18 trying to do is replace the existing.

19           When you look at the details of the terms of the  
20 QF Settlement, no new project is really going to be  
21 competitive with any existing project, they just -- I  
22 mean, but good old sure numbers, you know, you're already  
23 in the ground, you've already got your infrastructure, you  
24 don't have to go through a long queue at the ISO, you're  
25 favored if you're an existing project.

1           So the reality of this settlement is that it  
2   kind of held us at the status quo. And what I've been  
3   around the state preaching about is the settlement as a  
4   metaphor is a pier, not a bridge, and we really need a  
5   bridge. And what we need to work on now is the rest of  
6   the bridge. I think I'm today changing that metaphor  
7   because what it really says is we've walked out of the  
8   woods and we've come to the edge of the water, that's  
9   about as far as we've gotten. That's all this settlement  
10   does. Because, as Jennifer was just telling us, well, if  
11   we start playing with the Double Benchmark Standard, if we  
12   start looking at efficiencies, if we drive the future  
13   based solely on GHG reductions and forget anything else  
14   that CHP happens to provide as a benefit, like keeping  
15   manufacturing jobs in the state, keeping the tax rolls up,  
16   promoting the kind of efficiencies that you want out of  
17   these industries to operate, sustaining them in the state  
18   to be competitive, if you ignore all that and we just  
19   drive based on GHG efficiency alone, we've got a problem.

20           I mean, by Jennifer's own words today, and I  
21   appreciate her work and her candor and honesty, which  
22   she's essentially saying, "Well, if we start looking at  
23   how the grid efficiency should change, or if we start  
24   looking at Jerry's chart and we start trying to figure  
25   out, well, who isn't at 80 percent efficiency because

1 those ought to be out of here," we've failed. This  
2 settlement fails, to me. It doesn't do what we're trying  
3 to do, which is to carry forward a resource that has been  
4 essential or tremendously beneficial to the State, that  
5 for a number of reasons is disfavored its purchasers, its  
6 procurers.

7 Let's not get overly enthusiastic about the  
8 settlement. I'm very enthusiastic about what it did and  
9 I'm very proud of what it did, and I think there are some  
10 pats on the back about what it did, but it didn't get us  
11 out over the water and we need to get over the water and  
12 to the other side of the river. I'll be happy to talk  
13 about the questions that are presented dealing  
14 specifically with issues going forward, as well. Thank  
15 you.

16 CHAIRMAN WEISENMILLER: Thank you. I was just  
17 going to give at least one of the utilities, or Jennifer  
18 if they want to do a quick response to Michael that would  
19 be good, otherwise we'll switch to the questions. Sure,  
20 go ahead.

21 MR. TORRIBIO: Just a comment on maybe getting  
22 out over the water. The settlement does include  
23 mechanisms with the RFOs to buy power from new facilities.  
24 Now, it's been questioned today whether, under short run  
25 avoided costs new facilities could be built, but we're

1 talking about the RFO. And I guess I would just point to  
2 the experience of the utilities renewable -- the RPS RFOs,  
3 where nothing but new facilities are getting built under  
4 these, and I would offer a little bit more hope that maybe  
5 we have at least one part of the span over the water.

6 CHAIRMAN WEISENMILLER: Thank you. I think  
7 probably part of -- you know, I've heard Michael's speech  
8 before and I guess part of the concern on my part is just  
9 that the settlement negotiations were pretty much between  
10 existing QFs and the utilities, and whoever those future  
11 QFs were, you know, they were not going to get mired in  
12 trying to resolve all the litigation. But, frankly, at  
13 this point let's see what the solicitations do, you know,  
14 and hopefully we're getting closer to that point and then  
15 we can try and figure out what we have to do next. But at  
16 this point, at least I'm waiting to see the jury speak on  
17 this.

18 MR. WILLIAMS: I'll just point out one feature  
19 of the settlement, itself. If you're a new or repowered  
20 CHP qualified under that part of it, you're eligible for  
21 up to a 12-year PPA, whereas existing -- if you don't  
22 qualify, you're eligible for up to only a seven-year PPA.  
23 So obviously that number 12, you can imagine, there was  
24 quite a bit of discussion about that in the Settlement  
25 itself. And presumably those 12 years would be sufficient

1 to amortize an investment for at least some new facilities  
2 and that does provide an advantage for new or repowered QF  
3 CHP relative to those that don't make that investment.

4 CHAIRMAN WEISENMILLER: Thanks. Thanks for  
5 pointing that out.

6 MR. VIDAVER: Mr. Williams, in his brief  
7 discussion of what he's seeing so far on the RFO and can't  
8 talk any further about, said that there are existing  
9 resources that might shut down, the CPUC's Long Term  
10 Procurement Planning assumption is that existing CHP will  
11 continue to operate through the remainder of the Decade.  
12 It's my understanding that parties generally agree that's  
13 the case, but do -- and I'm directing this largely to Mr.  
14 Alcantar -- do you believe that there is a risk of a  
15 significant share of existing CHP retiring over the next  
16 10 years?

17 MR. ALCANTAR: Yes. There already has been a  
18 diminution of those facilities from contracts that have  
19 terminated and people shutting down. There are more  
20 strikingly from my experience, many many more potential  
21 projects that we have talked about, had evaluated, and  
22 they can't even get to the Boards. The advocates in this  
23 state who grew up with these kinds of facilities are going  
24 to look at programs where they still need processed steam  
25 if they're going to operate. There have been -- just, we

1    were counting up earlier today -- there are well over  
2    1,000 megawatts of CHP potential that are now being filled  
3    by boilers in the state. So it's already happening in a  
4    very negative way. Those are opportunities lost that you  
5    don't ever get back, you make that investment in a boiler,  
6    it's done, you're not going to come back and say, "Gee  
7    whiz, I made a mistake, let me rip those out and put in  
8    CHP." So, I think for the future, we already have a  
9    problem because we're seeing it presently. We've lost  
10   facilities that are coming off of contract that can't go  
11   forward under the payment levels that are there and, of  
12   course, we're now seeing new contracts that we'll see how  
13   that works out because, frankly, many of the contracts  
14   that we are seeing right now are inapplicable to the type  
15   of projects that are being offered.

16            MR. VIDAVER: Thank you. Turning from existing  
17   CHP to the potential for new CHP, it's the Phase 2 of the  
18   Settlement allows for utilities to use least cost/best fit  
19   criteria to decide whether to enter into contracts with  
20   CHP. I'd like to ask Mr. Williams and Mr. Torribio, Mr.  
21   Williams referred to reasonable cost and operating  
22   flexibility as two of the criteria of these to logically  
23   enter into a least cost/best fit determination, and that  
24   the CHP contracts have traditionally provided firm  
25   baseload. Can you -- would it be possible in general



1 terms to talk about the characteristics of CHP that would  
2 be most likely to meet less cost/best fit criteria, and  
3 whether or not you think existing CHP or new CHP is likely  
4 to have those characteristics?

5 MR. WILLIAMS: Sure. If you look at it from a  
6 procurement perspective, kind of a product sort of  
7 perspective, firm power priced competitively is certainly  
8 attractive to a utility. Efficient CHP is going to be  
9 more attractive because it will help us move toward the  
10 goal. One of the issues in the settlement, itself, was  
11 the ability to curtail during low load hours or there's  
12 actually a provision in there for some existing CHP to  
13 convert to a utility pre-scheduled facility, so they can  
14 obtain a contract that way. That certainly can help  
15 manage low load hours. But, you know, we are in a  
16 situation where electric demand growth is pretty flat  
17 right now and where we expect a pretty significant  
18 increase in intermittent generation, particularly from  
19 renewables. And if you put those two together, you know,  
20 we have clearly a -- we're focused on how do we manage  
21 that off-peak situation. And so that's part of the reason  
22 you see least cost/best fit, we're really looking at that  
23 and looking to see how that plays out over the next few  
24 years.

25 MR. TORRIBIO: Just to add, I think the key note

1 is that, just as the utilities -- as transmission and  
2 distribution providers are having to operate in quite a  
3 different environment in terms of integrating and  
4 increasing numbers of intermittent resources, and also  
5 dealing with the need to schedule loads and generation, I  
6 think the types of CHP projects that will be closest to  
7 the least cost/best fit may be to look at it from -- a  
8 little different prescriptive than Ray gave -- will be  
9 those that help the utility have more agility, more  
10 ability to integrate the whole portfolio of resources, and  
11 I can recall the first generation of QFs when we could  
12 sign up 100 megawatts at a time when we vertically  
13 integrated utilities, and it would barely move the needle.  
14 And those days are gone. So we're having to maneuver in  
15 what I would say are a lot more confined waters, and so  
16 the best projects will help us do that.

17 MS. KALAFUT: If I could make one comment on  
18 this, too, David? And it goes back to what Beth Vaughn  
19 pointed out from my slide, that she nicely characterized  
20 it as a clarification, but it was really a correction to  
21 the slide, which is that, if the utility procures an  
22 existing facility that is net GHG beneficial under the  
23 Settlement benchmarks, that will not count towards their  
24 GHG targets; whereas, procuring a new facility that is  
25 also net GHG beneficial, will count. So there is an

1 incentive there in terms of some new facility procurement  
2 and I hope to see that the RFOs, in addition to least  
3 cost/best fit, also take into other even more qualitative  
4 factors about what will compete and when in those  
5 solicitations.

6 MR. VIDAVER: Thank you.

7 MR. ALCANTAR: David, it might also help for the  
8 Commissioners to know -- Commissioner to know -- that  
9 there have already been filings of testimony by these two  
10 utilities and the other, identifying the fact that they  
11 need no new baseload generation, certainly, for CHP, so  
12 that's today, that's today. Now, I would like to think  
13 that will change, but that's what the LTP process is  
14 about, and it's important to understand that what also is  
15 critical in the settlement, and I think important for this  
16 Commission, but even more important for the CPUC, is that  
17 Commission doesn't have to live by the metric of GHG, it  
18 can determine that there are other reasons, other policy  
19 reasons, other procurement reasons, that they will direct  
20 these utilities to procure CHP regardless. And I think  
21 that's what I'm here to say. If you want to talk about  
22 hope, those are the things that have to happen, given what  
23 we're seeing about the kind of analysis, for example, that  
24 we see today. If you start sending additional messages to  
25 an already skittish investment community looking at these

1 resources, that not only is the metric in question, you're  
2 a seven-year contract, you don't know what's going to  
3 happen after that, you are already short in terms of being  
4 able to ease that debt, this is just the continuing spiral  
5 in message about it's time for you to go somewhere else.

6 MR. VIDAVER: Pursuing this -- I'm sorry.

7 MR. WILLIAMS: I would just have one  
8 elaboration. My understanding of the last Long Term  
9 Procurement Plan is that the Commission found no need for  
10 any type of generation, whether it was Base Load or  
11 dispatchable, and there was no Long Term RFO that followed  
12 that proceeding, in this particular cycle.

13 MR. ALCANTAR: I think you need to go back and  
14 look at the current decision on that point. They're still  
15 directing procurement for certain resources, it was your  
16 utility's position that you needed no resources, that  
17 wasn't adopted.

18 MR. WILLIAMS: Okay.

19 MR. VIDAVER: The ISO has stated it is beginning  
20 an investigation into a resource adequacy requirement  
21 related to resource flexibility, the flexible ramping  
22 capacity stakeholder proceeding. This would seem to imply  
23 an added value to not only the utility, but the system  
24 itself for resources that could be brought under the  
25 control of the ISO, moved up and down, and Mr. Williams

1 alluded to the need to curtail during low load hours, and  
2 Mr. Torribio talked about agility. Are we talking more  
3 generally about resources that can respond to either  
4 utility or ISO dispatch instructions in order to meet RA  
5 requirements associated with ramping, or other  
6 requirements that may be imposed by the system?

7 MR. ALCANTAR: I can take a swing at this one,  
8 to begin with. The issue that's counterintuitive to the  
9 CHP community is, for years, and even today, be efficient  
10 -- be more efficient -- be as efficient as you possibly,  
11 you know, use every single bit of your thermal demand in  
12 every possible way you can. And now, what' being  
13 suggested is, "Well, that's good, but if it doesn't match  
14 a flexibility profile, which it can't and doesn't, then  
15 you're disfavored. So I would rather be, you know, the  
16 old ugly name about a PURPA machine, I'm better off being  
17 a PURPA machine with that metric being the decision point  
18 about procurement. And that really is counterintuitive.  
19 We need to still have the most efficient thermal matching  
20 units we possibly can, and what's happened, thankfully,  
21 from a long litigation with the California ISO, that FERC  
22 ordered that, as long as there was as demonstrable thermal  
23 match by the host, you could not physically curtail below  
24 that designated level, so you've got some protection out  
25 of the so-called QFPGA. But that very protection, if

1 you're saying, well, no, I want flexibility to ramp you  
2 off and on, it again is counterintuitive to the process.  
3 Now, the other aspect of your question that is important  
4 is, under the settlement and under the settlement  
5 contracts, the product, the very minimum product that you  
6 sell, comes with three components -- capacity, associated  
7 energy, and the affiliated RA, all RA requirement go with  
8 it, so you don't have other RA to sell out of that  
9 capacity as it may be otherwise delivered. It's delivered  
10 with the product that you're bidding and selling in and  
11 providing. So you don't have the commercial flexibility  
12 to deal with that as a distinct product.

13 MR. VIDAVER: Lastly, the ARB assumption of a  
14 50-50 split between onsite generation and export would  
15 seem, if only based on Mr. Darrow's conclusions, to  
16 largely be accurate if you have export incentives and, as  
17 a result, you end up with rather large amounts of CHP. He  
18 reaches the Governor's target in 2030 in his high case, or  
19 comes quite close to it if my memory serves me correctly.  
20 Is it reasonable to assume that, if you have a planning  
21 assumption that yields a substantial amount of CHP -- I  
22 don't want to say what I think substantial is -- but if  
23 you were talking 3,000 or 4,000 megawatts, that a 50-50  
24 split between onsite use and export is reasonable, but if  
25 you're talking a scenario in which you only get 1,000

1 megawatts, you're talking about a 90-10 split towards  
2 onsite consumption. This is of interest to the Energy  
3 Commission because of the way we treat the load forecasts.

4 MR. ALCANTAR: There are two criteria drivers  
5 here, one is thermal match and one is electric match. The  
6 thermal match resource -- and I'll help Jennifer out here  
7 with one of her earlier comments -- the largest single CHP  
8 facility in the west is at the previous ARCO, now BP,  
9 called Watson Cogeneration Company, it's -- I think the  
10 nameplate there is roughly 419 megawatts. It's thermally  
11 matched. It was sized to meet its thermal load. If you  
12 look at another project that's familiar in this room, the  
13 Richmond Refinery, that facility always built essentially  
14 to meet a lumpy load growth thermal demand at its facility  
15 and it stayed behind the meter as much as it could, and  
16 often had some amount to sell as it was moving in. Those  
17 two differing dynamics tell a wide variety of tale about  
18 whether or not you can assume that there will be 50  
19 percent usage behind the meter and 50 percent export.  
20 It's highly variable. For example, in the Watson  
21 situation, early on in their initial operation, they were  
22 exporting well in excess of 300 megawatts. That's far  
23 less than 50 percent, and yet if you look at Richmond, I  
24 would say that were exporting at times close to zero, or a  
25 very small fraction of their total capacity. So you know,

1   there's no tried and true operation or presumption there  
2   unless you start saying, "What I want to do in this state  
3   is have thermal matching and as much efficient energy  
4   production from those resources as possible," and you  
5   incent that to happen.

6               CHAIRMAN WEISENMILLER:  Yeah, no, I think if you  
7   actually look at the AFCs for El Segundo and Watson, they  
8   both have roughly comparable steam loads.  Having said  
9   that, as Michael said, one is sized at 450 and the other  
10   is sized at roughly 100, and that's why when you do that,  
11   having said that, El Segundo has a remarkably low  
12   effective heat rate.  But, again, it's different corporate  
13   philosophies at the time.

14              MR. VIDAVER:  We do have one question that went  
15   out with the agenda, which is what do you think an  
16   appropriate planning assumption is for use in an LTTP  
17   Proceeding?  And I would suggest that, unless somewhat  
18   wants to opine on that subject, that we might ask you to  
19   answer that in written comments.  But if you want to take  
20   a shot at it now, go right ahead.

21              MR. WILLIAMS:  I'd like to take the liberty to  
22   make one comment about 1304 and then maybe try to address  
23   that question -- try to frame the question because I can't  
24   answer it.  So, the first is on, you know, I think as we  
25   move through implementation and we have new contracts and



1 new projects, monitoring or measuring the actual  
2 efficiency of CHP, I think it becomes more important  
3 because that gives you a better feel for how are you doing  
4 in terms of reducing emissions, how are you doing in terms  
5 of their efficiency, and the CEC itself has a 1304 Form  
6 and I believe it's in Schedule 2, Part A, you could ask  
7 some very simple information: what's the fuel input and  
8 type in MMBtu? What's the electrical output in MMBtu?  
9 And I believe you can find those in other parts of the  
10 form. But the one that's difficult is what is the used  
11 thermal output in MMBtu. And if that question could be  
12 asked simply and directly in a revision to 1304, I think  
13 that would be helpful because you generally survey a much  
14 broader part of the CHP community than, for example, PG&E  
15 will in its report that we'll file soon. We're really  
16 looking at what's in PG&E's service territory, so -- we'll  
17 add some additional detail in our comments.

18 Now, to go back and try to bravely answer your  
19 question, I talked to the people who are involved in the  
20 resource planning side, and you know, what we have a good  
21 picture of is, you know, what's going to happen in PG&E's  
22 service territory based on what we contract for. So we  
23 can't answer the question for the state, and we really  
24 can't look at contracts plus onsite, we don't see that.  
25 So it's pretty much a guess, but a decent range might be

1 in the year 2020, 400 to 800 megawatts nameplate and, you  
2 know, economic conditions have a lot to do with this, as  
3 well as maybe some of the policies going forward. Now, if  
4 you look at that from a resource adequacy perspective, you  
5 might get 80-90 percent on peak availability from that  
6 nameplate, so from that RA perspective which is kind of  
7 what's important from a procurement point of view, you're  
8 at 300 plus to 700 plus as a range. Now, onsite vs.  
9 export, I don't think we really have any idea, I think  
10 probably Michael has much more insight into that than PG&E  
11 would, so that's probably as much as I can share at this  
12 point, as much as I know.

13 MR. VIDAVER: This is for the PG&E service  
14 territory.

15 MR. WILLIAMS: Yes.

16 MR. ALCANTAR: And, Ray, do you happen to know  
17 if that's net new incremental over and above existing  
18 embedded CHP capacity?

19 MR. WILLIAMS: Yeah, I think 400, 800, or let's  
20 say 300 plus to 700 plus, it's a reasonable guess for new  
21 for PG&E service territory in the year 2020, this is just  
22 conversations with resource planners and this is the  
23 number that they threw out there.

24 CHAIRMAN WEISENMILLER: Yeah, coincidentally, in  
25 OII 26, PG&E's number was about -- actually, three

1 significant digits, but it was about 600 something, in  
2 contrast to the Governor's goal of 6,000 in how much it  
3 got.

4 MR. WILLIAMS: Well, at least I'm happy I'm  
5 within the range of what PG&E previously provided.

6 CHAIRMAN WEISENMILLER: That's right, yeah. And  
7 actually, in terms of some follow-up questions, in terms  
8 of the types of projects, getting back to what Dave said,  
9 one of the things that tends to drive the export vs.  
10 onsite is gas prices. And typically what we saw was, when  
11 people expected very high gas prices, that then the  
12 efficiency benefits of cogen tended to drive people to be  
13 sizing projects to do a lot of export, but as -- you know,  
14 if you just think that you have an efficiency wedge,  
15 that's obviously much more valuable at, say, \$6.00 than at  
16 \$3.00. You know, and certainly whenever you do cash flow  
17 modeling of a cogen project, if you double the gas price,  
18 it's going to look a lot better no matter what the number  
19 was. So that's one of the things that will affect that  
20 export, although obviously in California, you've got times  
21 when gas is on the margin and times when non-gas is on the  
22 margin, and the cogen can't compete effectively with hydro  
23 or other things, so it either has to become dispatchable  
24 or, you know, you've got to figure out some way not to be  
25 competing against, you know, dump hydro from the

1 northwest, or other non-gas resources. But the other  
2 thing that you tend to see is, when gas prices are low, is  
3 that the expectation is for increasing power prices, that  
4 ignoring the sort of exit fees, or type of things like  
5 that, tend to really drive projects more towards onsite.  
6 You know, again, when Chevron was investing, say, in  
7 Richmond, it was a very simple calculus to say, "We think  
8 gas prices are going to be flat in the near term, but we  
9 think power rights are going up." And so it was locking  
10 in that hedge. So, again, I think as we look at these, it  
11 does get back to what you think is going on in fuel prices  
12 and what you think is going on in power prices. So, as  
13 you think about how to respond to Dave's question, one of  
14 the things to think about is what your projections are for  
15 future gas prices and future power prices, particularly in  
16 that sort of industrial commercial classes.

17 MR. VIDAVER: I'd like to thank the panel for  
18 their time and effort and encourage them to file written  
19 comments on the questions I've raised, and other questions  
20 raised throughout. And if there are questions from the  
21 room or from the phone, perhaps now is the time to take  
22 them.

23 MS. KOROSSEC: We do have one question from the  
24 WebEx. We have David Erickson.

25 MR. ERICSON: Hello, can you hear me?

1           MS. KOROSSEC: Yes, we sure can. Could you step  
2 away from your computer because we're getting feedback  
3 from the time delay.

4           CHAIRMAN WEISENMILLER: Or mute your -- anyway,  
5 if you're on a speakerphone, please get off the speaker.

6           MR. ERICKSON: Okay. Is that still a problem?

7           MS. KOROSSEC: No, that's much better, thank you.

8           MR. ERICKSON: Okay, the question is, if a  
9 community choice aggregator is considering possibly  
10 constructing new CHP as part of a local portfolio, do you  
11 see the procurement or the GHG emissions reduction being  
12 handled differently than what the IOUs have been  
13 discussing? Or how do you see the overlap with the IOU  
14 issues?

15           MR. WILLIAMS: So this is Ray Williams from  
16 PG&E. As part of this settlement, we sort of built in the  
17 option for CCA and DA representatives in total, to either  
18 assume a portion of the CHP obligation or, instead, to pay  
19 the anticipated above-market costs of particularly the  
20 longer term contracts. The representatives of those  
21 groups chose not to purchase CHP, but instead to pay the  
22 above-market cost. So, to the extent, now, if you had a  
23 CCA that wanted to actually build or buy CHP, I don't see  
24 that as part of that settlement the megawatts would  
25 necessarily count because of the election that was made at

1 the end of the settlement by the CCA and DA  
2 representatives.

3 MR. ERICKSON: Okay, that's very interesting  
4 because that implies, then, that the settlement would have  
5 to be revisited in the case of, say, new CCAs that started  
6 that may want to handle CHP differently.

7 MR. WILLIAMS: I think process-wise, you would  
8 need to petition the PUC and the decision that adopted the  
9 settlement.

10 MR. ERICKSON: Okay, thank you very much.

11 MS. KALAFUT: And this is Jen Kalafut from the  
12 CPUC, just on this point, I mean, I agree with what Ray  
13 said, but I think the decision to build a new CHP facility  
14 within a CCA District, you know, may not only be  
15 contingent on whether or not it's counting towards the IOU  
16 megawatt or GHG targets, but you know, there are a lot of  
17 benefits that a CCA could see from developing a CHP  
18 project, including avoiding carbon costs in wholesale  
19 prices that are purchased through the IOU.

20 MR. ERICKSON: Right. I guess that was probably  
21 more specifically -- what my question related to was not  
22 so much whether the benefits would count toward the IOU  
23 procurement, but whether -- or how it would be handled in  
24 the context of the CCA contribution to meeting the AB 32  
25 goal, if that makes sense. Does that make sense?

1 MS. KALAFUT: Yeah, and in terms of contribution  
2 to the AB 32 goals, again, if the CHP is lowering the  
3 total emissions profile of the CCA, that's going to -- I  
4 can't speak for the ARB and how they're accounting for  
5 this, but I would imagine that that would count towards AB  
6 32 goals for CHP.

7 CHAIRMAN WEISENMILLER: Yeah, let me encourage  
8 you, in terms of if you have specific suggestions in this  
9 area, that you file those as part of your written  
10 comments.

11 MR. ERICKSON: Okay, thank you very much. I  
12 will do that.

13 MS. KOROSSEC: We do not have any more comments  
14 from online speakers.

15 CHAIRMAN WEISENMILLER: Is there anyone else in  
16 the room who wants to comment? Sure. Please identify  
17 yourself.

18 MR. WOLFIT: Greg Wolf with NextEra Energy and I  
19 had a question for Ray regarding, I guess, 487 megawatts,  
20 or whatever the number was, that had been re-contracted,  
21 and the general feeling around any of your Sellers  
22 Conference regarding the risks of energy imbalance and the  
23 new risks that appear to be in place under the new  
24 contract that's being offered vs. the old QF Agreements.

25 MR. WILLIAMS: Actually, I'll speak to it, but

1 my guess is Michael is probably going to correct some of  
2 the things that I say, but to the extent when you sign a  
3 new contract it moves you into ISO tariff requirements,  
4 then there are new obligations that a CHP generator has.  
5 One of them has to do with scheduling. I believe the  
6 utility could offer that service, or they could get it  
7 through some third party. And I'm sure there are other  
8 obligations, as well, and I would be happy to sort of pass  
9 the baton here to Michael to complete the answer.

10 MR. ALCANTAR: If you do not use the utility as  
11 a scheduling coordinator, you do expose yourself to a  
12 wider array and deeper array of potential imbalance  
13 charges, so the way the pro formas are written, it's  
14 highly encouraging incentives to make you elect the  
15 utility, your interconnected utility, as your scheduling  
16 coordinator. Having done that, then, no matter -- either  
17 way -- you are truly at risk if you fail in any 15-minute  
18 interval to be extraordinarily careful about communicating  
19 any real time changes to your day ahead hourly schedule  
20 because those will expose you to imbalance penalties if  
21 you haven't informed your scheduling coordinator so they  
22 can correct them.

23 CHAIRMAN WEISENMILLER: Sure.

24 MR. NEFF: One last comment or a question on the  
25 3,000 megawatt target. Once that target is reached, does



1 it have to be maintained? Or is it just a single, you  
2 reach it, and then you have no other further megawatt  
3 pulls?

4 MR. ALCANTAR: Absolutely. It can't be backed  
5 off. I think there's a dispute about that right at the  
6 moment in terms of county rules, but in my view?  
7 Absolutely. It's to be maintained and sustained. And the  
8 question then becomes how do utilities administer that,  
9 how the CPUC accounts for it.

10 MS. KALAFUT: Well, I think it's important to  
11 keep in mind that the -- and correct me if I'm wrong here,  
12 Michael, or anyone else -- but that the megawatt target is  
13 by 2015, 48 months from November 2011, so November 2015.  
14 And at that point, that's when the 3,000 megawatt target  
15 will be assessed. There's nothing going to be signed -- I  
16 mean, between now and then, there's nothing going to be  
17 signed, necessarily, you know, less than four years. I  
18 mean, there's potential for that to happen, but if  
19 something -- if a facility signs up a seven-year contract,  
20 then it expires in 2017 or 2018, those megawatts would  
21 still count towards the megawatt goal.

22 MR. ALCANTAR: I think the difficulty with that  
23 counting mechanism is that you've failed to maintain  
24 another metric in the settlement, which is you are to  
25 sustain the GHG benefits associated with the retained

1 fleet. And so you've got another issue to try to address  
2 in that county. So I would argue, no, if that expires  
3 you've got to make it up in megawatts because you've got  
4 to be able to recount GHG to get there.

5 MR. TORRIBIO: I would question that  
6 interpretation. I believe it's counted at the time of  
7 execution of the contract, I don't think it says anything  
8 about in perpetuity, or follow-up monitoring of the  
9 megawatt total.

10 MR. ALCANTAR: So if that were the improper  
11 interpretation, Jerry, we have an instantaneous 3,000 mega  
12 -- you could sign 3,000 megawatts for a day and the end of  
13 the program occurs, so that doesn't seem to be logical to  
14 us. But we can deal with it.

15 MS. KALAFUT: But this is being worked out in  
16 the accounting and reporting rules and template that we're  
17 putting in place right now, so we will have this worked  
18 out by the end of March, before the first reports are due.  
19 Okay.

20 CHAIRMAN WEISENMILLER: Okay. If there are no  
21 other comments, I'd like to really thank everyone in the  
22 room, with the last interchanges, encouraging to hear a  
23 dysfunctional family in this area is still somewhat  
24 dysfunctional, although not as much as in the past. But  
25 again, I think the basic message is that certainly this

1 Governor and this Administration, you know, really want to  
2 see cogen move, and are really looking for the utilities  
3 to bring in creativity and initiative to really move these  
4 programs along.

5           And certainly, again, from part of our  
6 conversation today, I think certainly looking for ways  
7 that we can find additional value in cogen, you know, I  
8 know the typical is Base Load, but obviously those of us  
9 who worked for Crockett know that you could have a project  
10 that is shut down every night, you know, and still meets  
11 its steam loads, and its PURPA requirements, and actually  
12 provide VAR support, and provides VAR support to PG&E. So  
13 one can get creative. I certainly would encourage people,  
14 particularly on the ends of some of the transmission  
15 lines, to think about ways to get projects there, you  
16 know, to enhance the reliability for places like 29 Palms,  
17 or -- I think that was one of the original drivers for  
18 Trona, or I can point to any number of projects in the  
19 '80s which, at the end of transmission lines in the cogen  
20 projects really enhanced the service and it was certainly  
21 avoiding, you know, major upgrades to the distribution or  
22 transmission system that, again, if we can do that, it  
23 helps, so if there are ways that they can provide ramping,  
24 although I hadn't -- until Michael mentioned it, I hadn't  
25 thought about the RA issue, and I'm sure the contracts

1 basically say it's already contracted out. So, again, it  
2 may be that you need -- you know, one of the features of  
3 the '80s obviously was just standard offer and then  
4 everyone tried to find ways to tweak the projects, tweak  
5 the contract and provide somewhat more value going  
6 forward. And presumably -- hopefully the negotiations in  
7 response to the RFPs will allow some creativity to tweak  
8 the contracts and get some additional ratepayer benefits  
9 out of them. So anyway, Andy, excuse me, do you have a  
10 comment?

11 MR. BROWN: Yes, thank you, Chairman. Andrew  
12 Brown with Ellison, Schneider and Harris. I didn't  
13 realize you were trying to close out the public comment  
14 period. But I'm here on behalf of two entities, one is  
15 Ace Cogen and the other entity, or actually, the Rio Bravo  
16 Poso and Jasmine entities. These are a handful of the  
17 solid fuels, the QFs that exist in the state. And the  
18 advance of the GHG program obviously put these facilities  
19 in a bit of peril. Ace Cogen itself is located out in  
20 Trona at the end of the line, and it was sited by this  
21 Commission in an effort when the state was fostering fuel  
22 diversity and actually was encouraging coal and petcoke-  
23 fueled projects. We now find ourselves on the other end  
24 of the pendulum swing, where these types of projects are  
25 being encouraged to go away about as quickly as you can.

1           They are trying to look at options and the CHP  
2 program potentially is one. But, as you can imagine, the  
3 way that these type of assets will achieve a more  
4 preferred GHG emission profile isn't by enhancing  
5 efficiency of the projects, it's by fuel switching. And,  
6 unfortunately, CARB, despite a few pleas and efforts on  
7 our part to have a transition pathway developed for the  
8 fuel transition for these types of facilities, that was  
9 never laid out as an option. And so now we're trying to  
10 manage to find a path to make significant capital  
11 investments that are required for fuel switching.

12           Now, Ace is tied to an industrial facility that  
13 also is operating its own coal boilers in the facility  
14 itself, besides providing thermal energy on a continuous  
15 basis, also functions as a backup to the industrial site's  
16 facilities because, if the industrial site's facilities  
17 fail, then it's entire industrial operations sort of  
18 literally seizes. And so the transition from coal,  
19 petcoke solid fuels to natural gas will have a large bit  
20 of infrastructure and planning involved with that.

21           Not quite similarly, but not dissimilarly, the  
22 Rio Bravo, Jasmine and Poso facilities are solid fueled,  
23 they're located in assisting in enhanced oil recovery, so  
24 there's a little bit of a different nature in the  
25 industrial activity; they're in the process right now of

1 looking to convert some of their fuel handling because  
2 they're locating in the location where they can take  
3 advantage of some biomass opportunities.

4 But, again, this is a handful of projects the  
5 state originally had, no pathway for a fuel conversion,  
6 which is the way to get the desired GHG profile in place,  
7 was developed as any part of the state's AB 32 process.

8 So whether or not they're considered new or  
9 existing CHP, or things that we'll be looking into in  
10 terms of participating in the utility CHP Programs, but I  
11 wanted to point these out to the Commission today because  
12 I think they're examples of projects that were developed  
13 with the CHP and efficient use of fuels, those policies in  
14 mind, and now they're really being orphaned by the state  
15 with the change of environmental policies.

16 And it would be most helpful if there was a  
17 transition pathway that wouldn't cause a significant  
18 economic dislocation for these projects, the folks they  
19 employ, and the localities which benefit from their  
20 injection of taxes, etc.

21 CHAIRMAN WEISENMILLER: Okay, thanks. Any other  
22 public comment either in the room or on the phone?

23 I again thank all the speakers from today and  
24 certainly the staff for organizing this, and this meeting  
25 is adjourned.

[Adjourned at 4:49 P.M.]

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